FEASIBILITY OF ALTERNATIVE MEANS OF COOLING FOR THERMAL POWER PLANTS NEAR LAKE MICHIGAN

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FEASIBILITY OF ALTERNATIVE MEANS OF COOLING FOR THERMAL POWER PLANTS NEAR LAKE MICHIGAN

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I. INTRODUCTION

Scope

This report presents an evaluation of various methods of dissipating waste heat from thermal power plants near Lake Michigan. The feasibility of the cooling methods are considered from both an engineering and economic standpoint.

It must be emphasized at the outset that the following analyses are directed towards determining the feasibility of various cooling methods; no attempt is made to optimize any particular plant or site.

In addition to determining the engineering and economic feasibility of cooling devices, the effect of their operation on the environment is examined.

Waste Heat Load

The engineering calculations on the various cooling devices are made on the basis of a "typical" 1000 MWe fossil-fueled power plant with a nominal thermal efficiency of 40 percent. With in-plant and stack losses of 15 percent of the total heat input, such a plant will discharge 3.84×10^9 Btu/hr to the condenser cooling water. This same waste heat load would be created by a 600 MWe nuclear power plant with a boiling water or pressurized water reactor, assuming a nominal thermal efficiency of 33 percent and 5 percent in-plant losses. Other combinations of plant size and thermal efficiency which result in 3.84×10^9 Btu/hr waste heat to cooling water are shown in Figure I-1 for both 5 percent and 15 percent in-plant losses. For example, a 750 MWe fossil-fueled plant (15 percent in-plant losses) with a thermal efficiency of 34 percent has a waste heat load equivalent to the "base" 1000 MWe, 40 percent efficient plant.

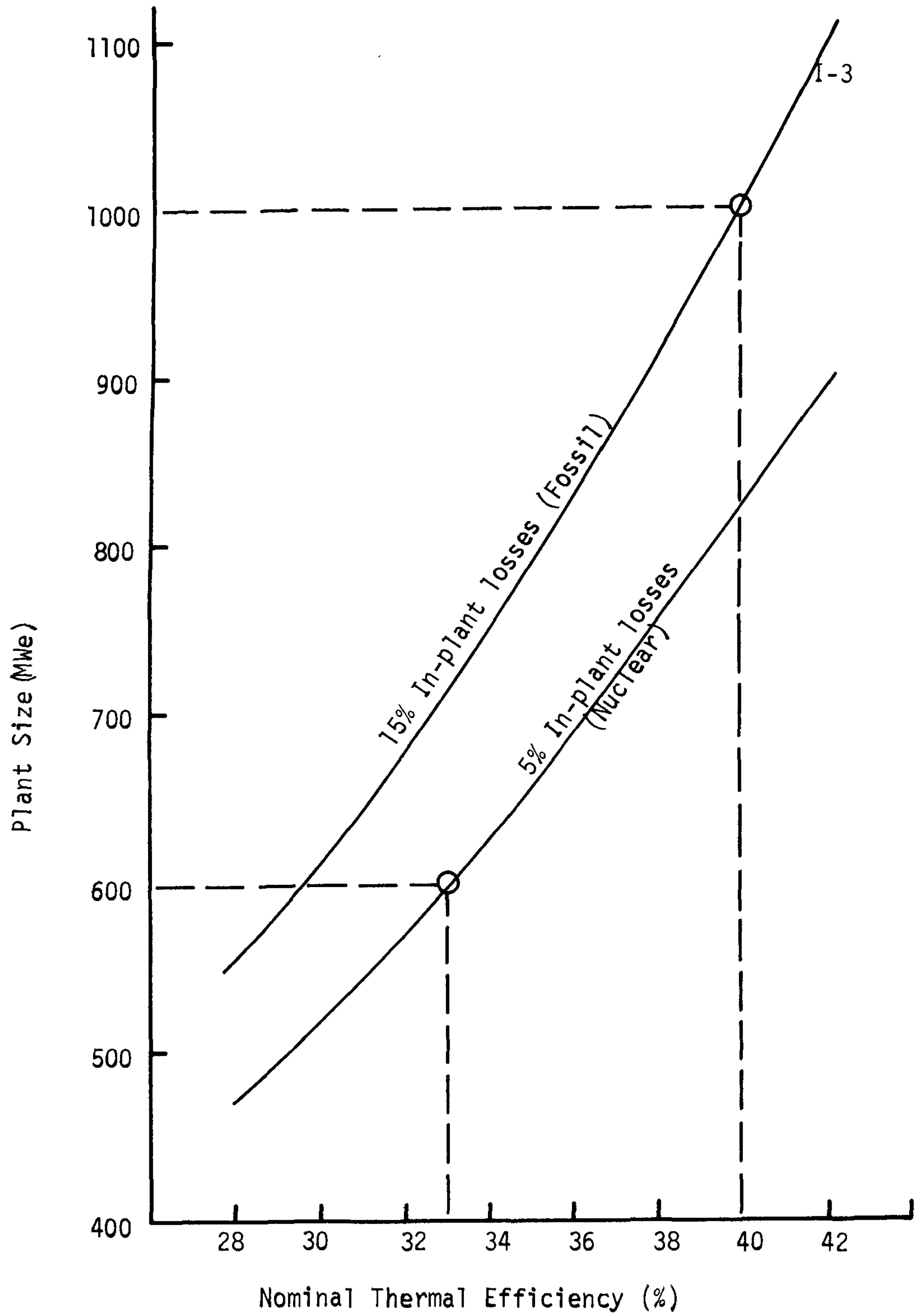

Figure I-1: Equation of Plant Size and Thermal Efficiency for Waste Heat to Cooling Water of $\underline{\underline{3.84 \times 10^9 \text{ Btu/hr}}}$.

Cooling Methods

A wide variety of cooling methods are available for dissipating waste heat from thermal power plants. The feasibility of the following cooling devices are evaluated:

1) Evaporative cooling towers
    a) Mechanical draft
    b) Natural draft
2) Cooling ponds
3) Spray cooling canals
4) Dry cooling towers (Heller System)
    a) Mechanical draft
    b) Natural draft

A cooling system employing each of the above devices is sized for a closed-cycle, recirculating configuration using design meteorological data representative of critical summertime conditions. The annual operating characteristics and costs of the selected systems are evaluated using long-term seasonal average weather conditions.

Regional Considerations

In order to account for regional variations in climatic conditions, the Lake Michigan area is divided into four geographical sections. Figure I-2 shows these four sections: NW, NE, SE, and SW. Personnel at the Weather Bureau Office in Chicago agreed that the four sections are representative of the climatic areas around Lake Michigan. As can be seen from Figure I-2, the NW section is bounded by the Mackinac Straits in the north and Sheboygan, Wisconsin in the south; the SW section extends from Sheboygan to Gary, Indiana; the SE section lies between Gary and Pentwater, Michigan; and the NE section extends from Pentwater to the Mackinac Straits.

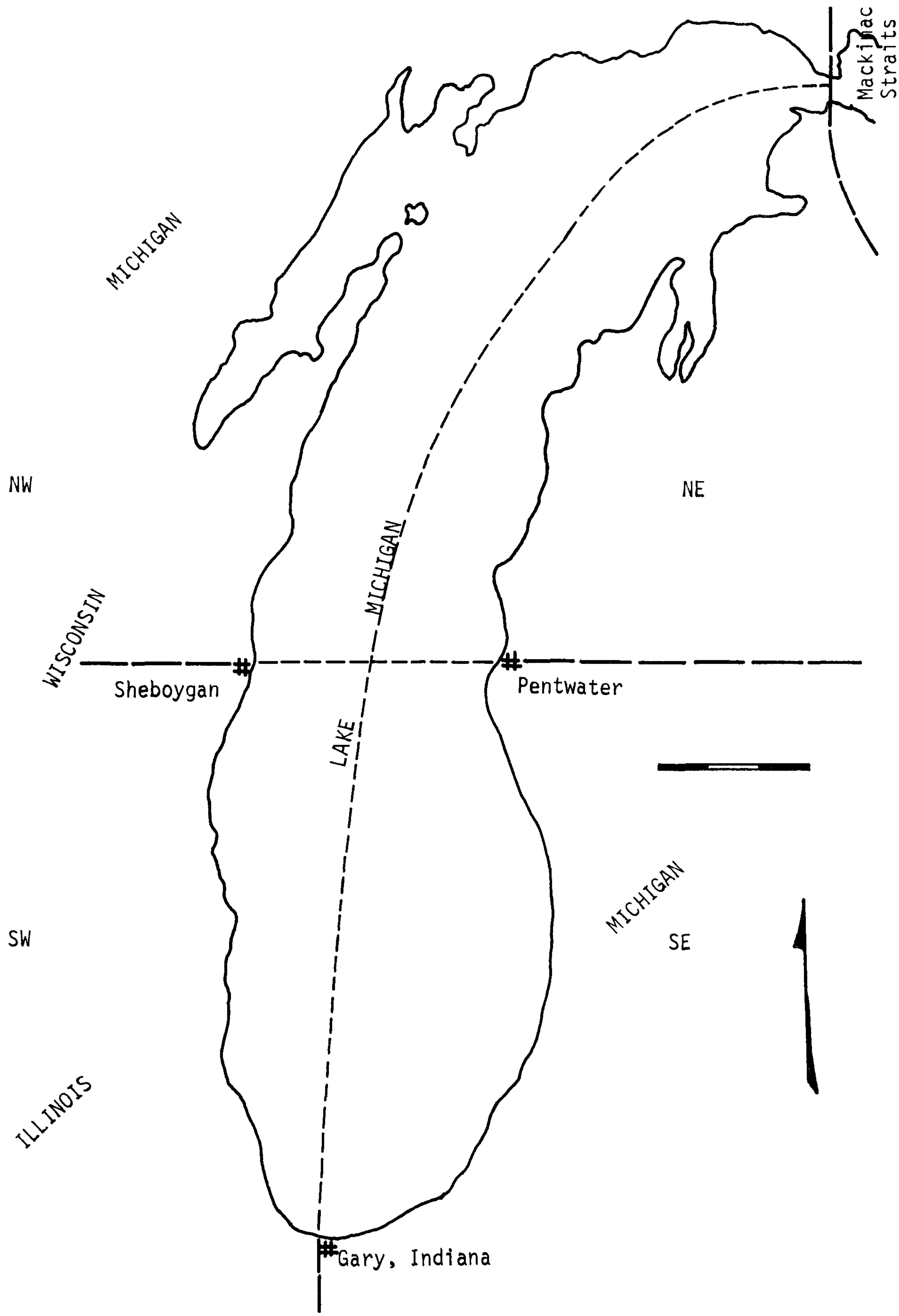

Figure I-2: Climatic Sections -- Lake Michigan

II. METEOROLOGY

Data Requirements

The operation of the devices used to dissipate waste heat is primarily a function of the weather. Therefore, an evaluation of their feasibility requires an accurate set of meteorological data. Significant variations in the design climatic factors with respect to season and location must be accounted for.

The nature of the heat transfer phenomena which a particular cooling device uses to dissipate heat to the atmosphere determines the meteorological data requirements for the device. A compilation of the heat transfer mechanisms and associated meteorological data requirements for the alternative heat dissipation methods is given in Table II-1.

In addition to the weather data requirements shown in Table II-1, information on lake temperatures is needed to compare once-through cooling systems with the alternative cooling systems.

Seasonal Considerations

Four seasons are selected to represent a full annual cycle:

Winter	-	December, January, February
Spring	-	March, April, May
Summer	-	June, July, August
Fall	-	September, October, November

TABLE II-1

METEOROLOGIC DATA REQUIREMENTS

Cooling Method	Heat Transfer Mechanism	Meteorologic Data Required
Evaporative Cooling Towers	Convection Evaporation	Dry-bulb Temperature Relative Humidity*
Cooling Ponds	Radiation Convection Evaporation	Solar Radiation Dry-Bulb Temperature Relative Humidity* Wind Speed Cloud Cover
Spray Cooling Canals	Evaporation Convection	Dry-bulb Temperature Relative Humidity* Wind Speed
Dry Cooling Towers	Convection	Dry-bulb Temperature

*Wet-bulb or dew point temperature can also be used.

Meteorological Data Summary

Table II-2 presents a summary of average meteorological data for each of the four seasons and geographical sections. The major data source used to compile this table was the Climatic Atlas of the United States (Reference II-7) prepared by ESSA in 1968. This publication presents a wide variety of weather data on maps with isolines for the specified meteorological parameter.

Data for the parameters shown in Table II-2 were obtained as follows:

(1) Dry-bulb Air Temperature

Average monthly temperatures were compiled for each of the four seasons for the four sections from maps on pages 1-23 of the Atlas. These data are shown in Table II-3.

(2) Relative Humidity

Average monthly relative humidities were compiled from maps on pages 61 and 62 of the Atlas. While seasonal variations were detected from these maps, it was difficult to obtain enough detail to show variations in relative humidity between the four sections around Lake Michigan. These data are given in Table II-4.

(3) Wet-bulb Air Temperature

These data were calculated from the dry-bulb temperature and the relative humidity using tables relating wet-bulb depression (i.e., dry-bulb minus wet-bulb temperature) versus relative humidity (Reference II-15).

TABLE II-2

METEOROLOGICAL DATA SUMMARY — AVERAGE CONDITIONS

Section	Season	(1) Dry-bulb Air Temperature (°F)	(2) Relative Humidity (%)	(3) Wet-bulb Air Temperature (°F)	(4) Cloud Cover (1/10's)	(5) Wind Speed (mph)	(6) Solar Radiation (ly/day)
NW	Winter	21	80	20	8	11.0	160
	Spring	42	70	38	6	11.4	400
	Summer	67	70	61	5	8.8	510
	Fall	49	75	45	7	10.4	230
SW	Winter	25	80	23	8	11.0	160
	Spring	45	70	41	6	11.4	400
	Summer	70	70	64	5	8.8	510
	Fall	52	75	48	7	10.4	230
SE	Winter	27	80	25	8	11.0	160
	Spring	46	70	42	6	11.4	400
	Summer	70	70	64	5	8.8	510
	Fall	52	75	48	7	10.4	230
NE	Winter	23	80	22	8	11.0	160
	Spring	41	70	37	6	11.4	400
	Summer	66	70	60	5	8.8	510
	Fall	49	75	45	7	10.4	230

TABLE II-3

AVERAGE MONTHLY DRY-BULB TEMPERATURES (°F)
(Reference II-7)

Month	Season	Section			
		NW	SW	SE	NE
December		24	27	30	27
January		20	23	26	21
February		20	24	25	21
	Winter	21	25	27	23
March		30	34	35	30
April		42	45	46	42
May		55	56	56	52
	Spring	42	45	46	41
June		63	66	67	62
July		69	72	72	68
August		68	71	71	67
	Summer	67	70	70	66
September		61	64	64	61
October		50	53	52	50
November		36	38	40	36
	Fall	49	52	52	49

TABLE II-4

AVERAGE MONTHLY WEATHER DATA

Month	Season	Relative Humidity (%)	Cloud Cover (1/10's)	Solar Radiation (ly/day)
December		80	8	120
January		80	8	125
February		80	7	225
	Winter	80	8	160
March		70	7	325
April		70	6	400
May		70	6	475
	Spring	70	6	400
June		70	6	525
July		70	5	525
August		70	5	475
	Summer	70	5	510
September		75	6	350
October		75	6	225
November		75	8	125
	Fall	75	7	230

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(4) Cloud Cover

Maps on pages 71 and 72 of the Atlas were used to obtain cloud cover data. As with relative humidity, sectional variations were difficult to determine. Table II-4 contains the monthly and seasonal data.

(5) Wind Speed

The wind data were obtained from Asbury (Reference II-1), where average monthly wind speeds from Chicago, South Bend, Escanaba, Muskegon, Sault Ste. Marie, Green Bay, and Milwaukee were compiled for the years 1952, 1953, 1954, 1955, 1960, and 1962 and plotted in a curve showing wind speed versus month for a complete annual cycle (Figure 7 of Reference II-1).

(6) Solar Radiation

Data for mean daily solar radiation were obtained from the Atlas using maps on pages 69 and 70 and are presented in Table II-4. Again, variations between the four sections were difficult to detect.

Design Meteorological Data

While the weather information presented in Tables II-2, II-3, and II-4 is useful in evaluating the performance of a particular cooling device over a complete annual cycle, it is not appropriate for designing the device. Cooling systems must be designed to assure adequate performance under all conditions, not just under "average" conditions. Therefore, one usually selects a set of design data which represents a severe condition from the standpoint of operating the cooling device.

Severe summertime weather conditions represent the "design" case for thermal power plant cooling systems operating in the vicinity of Lake Michigan. This is true for two reasons:

(1) The efficiency with which the cooling device dissipates heat to the atmosphere is lowest during the summer.

(2) The demand for electric power and hence the requirement for full load operation of the plant is highest during the summer for the majority of electrical consumers in the area.

Table II-5 shows the design conditions selected for the four sections.

TABLE II-5

DESIGN METEOROLOGICAL DATA

	(1)	(3)	(4)	(5)	(6)	(7)
Section	Dry-bulb Temperature (°F)	Wet-bulb Temperature (°F)	Cloud Cover (1/10's)	Wind Speed (mph)	Solar Radiation (ly/day)	Equilibrium Temperature (°F)
NW	82	70	0	8.8	750	85
SW	86	74	0	8.8	750	87
SE	85	73	0	8.8	750	86
NE	83	71	0	8.8	750	85

The data in Table II-5 were selected as follows:

(1) and (3) Dry- and Wet-bulb Temperatures

The Marley Company, one of the nation's largest manufacturers of cooling towers, states in Cooling Tower Fundamentals and Application Principles (Reference II-14, page 8):

> "Performance analyses have shown that most industrial installations based upon wet-bulb temperatures which are exceeded by no more than 5% during a normal summer have given satisfactory results. The hours that the wet-bulb temperature exceeds the average maximum by 5% need not be consecutive hours and may occur in periods of relatively short duration."

On the basis of this recommendation, as well as others (Reference II-13, page 157), wet- and dry-bulb temperatures not exceeded more than 5 percent of the time during the months of June through September were selected as design conditions. The Marley Company has tabulated these data for a large number of U. S. and foreign cities (Reference II-14) and Table II-6 gives these data for various locations around Lake Michigan with averages for each of the four selected sections.

(4) Cloud Cover

Zero cloud cover was selected as the design condition to coincide with the occurrence of maximum solar radiation.

TABLE II-6

DESIGN DRY- AND WET-BULB TEMPERATURES (°F)
(Reference II-14)

City	State	Section	Dry-bulb	Wet-bulb
Oshkosh	Wisconsin	NW	85	72
Green Bay	Wisconsin	NW	82	72
Manitowoc	Wisconsin	NW	82	72
Iron Mtn.	Michigan	NW	83	68
Marquette	Michigan	NW	78	68
		Ave. NW	82	70
Chicago	Illinois	SW	89	75
Milwaukee	Wisconsin	SW	84	73
Burlington	Wisconsin	SW	85	73
Aurora	Illinois	SW	88	75
		Ave. SW	86	74
Muskegon	Michigan	SE	82	73
Grand Rapids	Michigan	SE	85	73
Benton Harbor	Michigan	SE	84	73
Michigan City	Indiana	SE	87	74
Gary	Indiana	SE	86	74
		Ave. SE	85	73
Traverse City	Michigan	NE	83	72
Charlevoix	Michigan	NE	84	71
Manistee	Michigan	NE	83	72
Glen Arbor	Michigan	NE	82	71
		Ave. NE	83	71

(5) Wind

The selection of a design wind speed is made difficult by the lack of data on the temporal distribution of wind velocity in the Lake Michigan area. Available U. S. Weather Bureau data do not provide adequate information of this type. Therefore, the average summer wind speed data from Asbury (Reference II-1) is applicable as the design case, since it does represent the wind condition concurrent with the other design meteorological variables. Also, only cooling ponds have wind speed as a major design variable, and the large retention time in ponds makes the average wind speed an appropriate design variable.

(6) Solar Radiation

One of the most complete summaries of meteorological data for the Lake Michigan region was prepared by Moses and Bogner from data collected at the Argonne National Laboratory Weather Station (Reference II-19). This summary includes a complete compilation of solar radiation data for September 1950 through December 1964. Figure 46 on page 244 of Moses and Bogner (Reference II-19) gives a percentile distribution of daily total solar radiation. A value of 750 langleys/day represents the June-July conditions at the 95 percent level (i.e., exceeded not more than 5 percent of the time). Therefore, this value was selected as the design condition.

(7) Equilibrium Temperature

The equilibrium temperature of a body of water is reached when the net exchange of energy at the water surface equals zero. In other words, it is the temperature reached by a body of water exposed to a given set of climatic conditions for an infinite period of time (i.e., until equilibrium is reached).

Column 7 of Table II-5 shows the equilibrium temperature for each geographical section for the design meteorological conditions in Columns 1, 3, 4, 5, and 6. The computations were made using a computer program (Reference II-9) according to methodology described by Edinger and Geyer (Reference II-8).

Theoretical Limitations of Cooling Devices

Each of the cooling devices discussed previously have theoretical limits on their ability to cool water. These limits are as follows:

Wet Tower -- Wet-bulb temperature

Cooling Pond -- Equilibrium temperature

Spray Cooling Canal -- Wet-bulb temperature

Dry Tower -- Dry-bulb temperature

The data in Table II-5 can be used to determine the theoretical lower limit of cooling for each device in each of the four geographical sections. It should be emphasized, however, that engineering and economic considerations require the outlet temperatures from the cooling devices to exceed these theoretical lower limits.

Lake Temperatures

Numerous publications (References II-1-6; 10-12; 16-18; 20-22) contain information on the temperature of Lake Michigan. However, no available compilation of data adequately describes the temporal distribution of temperatures in the nearshore areas where power plants would obtain cooling water. Good sources of data for the nearshore zone are municipal water intakes and existing power plant intakes. Table II-7 presents values for average water temperature determined from these records for each of the four geographical sections.

The following sources were used to compute the data in Table II-7:

SW - Gary, Indiana and Milwaukee, Wisconsin water intakes; average depth = 38 feet; average distance from shore = 6500 feet; time period: 1959-1969. These stations are part of the National Water Quality Network; the data are contained in FWQA's "STORET" Information System.

SE - St. Joseph, Benton Harbor, Holland, Grand Rapids, and Muskegon, Michigan water intakes; average depth = 40 feet; average distance from shore = 4500 feet. These values were developed from Michigan Water Resources Commission data for maximum, minimum, and 90 percentile temperatures (Reference II-16). The SW region data and surface water data (References II-4,10,16) were used as aids in establishing specific values.

TABLE II-7

AVERAGE LAKE TEMPERATURES (°F)

Month	Season	Section NW	SW	SE	NE
December		34	39	40	35
January		34	35	34	34
February		33	34	34	34
	Winter	34	36	36	34
March		34	36	36	35
April		36	41	41	37
May		43	46	47	44
	Spring	38	41	41	39
June		49	51	52	50
July		53	55	57	54
August		54	56	58	55
	Summer	52	54	56	53
September		60	61	61	60
October		52	55	55	53
November		42	47	47	44
	Fall	51	54	54	52

NE - Ludington and Big Rock, Michigan water intakes; average depth = 30 feet; average distance from shore = 2200 feet. These data were also developed from Michigan Water Resources Commission data. SW region data and surface water data were again used as aids in establishing specific values.

NW - Escanaba, Michigan steam station water inlet temperatures; shoreline intake. These data are not very representative of the NW region, however, data from the NE and SW regions were used to establish values along with BT data (Reference II-10). It is a common rule of thumb that the Wisconsin side of the lake is slightly cooler than the Michigan side in summer and roughly the same at other times.

In addition, a design lake water temperature is needed to size a plant's once-through condenser system for comparison with the alternative cooling systems. The above sources were used to establish temperatures at the 95 percentile level. Averages of the 95 percentile values for the three summer months are shown in Table II-8 and used as design temperatures for the four geographical sections.

TABLE II-8

DESIGN LAKE TEMPERATURES (°F)
(95 Percentile)

Month	Section			
	NW	SW	SE	NE
June	60	64	65	60
July	67	71	72	68
August	69	72	73	70
Summer	65	69	70	66

It should be recognized that the temperatures in Tables II-7 and II-8 refer to points in the main body of the lake at about a mile from shore and at depth. Surface and beach water tend to follow air temperature more closely and display more daily and yearly variation; similar remarks apply to Green Bay, Traverse Bay and the southern tip of Lake Michigan. As an example, data from several municipal water intakes between Chicago and Gary, Indiana indicate 95 percentile temperatures as much as 4 degrees warmer than shown for the SW section in Table II-8.

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III ECONOMIC CONSIDERATIONS

General Cost Factors

The cost of power generation, i.e. the busbar cost, is expressed in Mills/KWH and is usually broken down into fixed and variable cost components. Fixed charges are those which are unaffected by plant output and include interest on money, amortization of the plant capital cost, interim replacements, insurance, and taxes. Although income taxes vary somewhat with plant use, they are usually included in fixed charges because they are reasonably predictable and the courts have held that the return which a utility is entitled to earn must be computed after allowance for such taxes (Reference III-4). The annual fixed charge rate is expressed as a percentage of plant capital cost. It is the sum of the charges alloted to each contributing item noted above. In determining the fixed cost contribution to total busbar cost, the annual cost is calculated in dollars and then converted to Mills/KWH in accordance with plant operation time.

Variable costs, also called operating costs or production costs, are those associated with the amount of generation and include fuel, payroll labor, and other operating and maintenance expenses. Each of these items is expressed in terms of Mills/KWH.

Both fixed and variable costs are influenced by the heat dissipation system of a plant. The opposite is also true, because general cost factors play a major roll in the optimal design of a plant-cooling system combination. Hence, it is important to establish economic criteria in the early stages of this study.

The sum of charges noted above make up the busbar cost of power from a given plant without regard to its location. For an overall optimization of power costs at the load center in a large system, the location of a new plant must also be assessed in terms of transmission and distribution costs. These costs may outweigh additional costs involved in off-stream cooling devices. Battelle Northwest (Reference III-2) cites a cost of about 0.3 Mills/KWH per 100 miles of transmission. This figure is substantiated by the analysis of Hauser (Reference III-6) who concludes that the additional cost of wet cooling towers, about 0.2 Mills/KWH, is equivalent to a transmission distance of about 80 miles. In a discussion of evaporative cooling systems related to costs of nuclear plants at numerous locations throughout the United States, Kempf and Fletcher (Reference III-7) state that "...the use of a costlier evaporative system at a site situated favorably with respect to load centers may be economically preferable to the transmission of power from sites which can use once-through cooling but are remote from load centers."

Study Approach

The economic analysis is directed toward the effect of cooling system choice on the total busbar cost of generating power. An economic life of 30 years is assumed for all plants and systems considered.

Initially, an attempt was made to determine the representative capital and operating costs for the "Typical" 1000 MW fossil fuel plant which could be studied at a number of general sites around Lake Michigan. Such a single plant approach was found to be unreasonable because of the wide variation in capital costs and operating costs, including fuel, for existing plants adjacent to the Lake. Federal Power Commission data (Reference III-5) for ten such plants built since 1960 reflect capital costs ranging from $105 to $186/KW. For the same plants, operating costs (i.e., fuel, operation and maintenance) ranged from 2.20 to 3.53*Mills/KWH. Such variations of over 60 percent indicate the potential inaccuracy in assuming a single set of cost values to be representative throughout the study area. This is particularly true when assessing additional costs of alternative cooling systems since the busbar cost increase for alternative systems, other than dry cooling, will be less than 5% (Reference III-6).

In order to provide a meaningful interpretation of plant economics for a number of sets of cost factors, three rate values are used for each cost component which might vary from one situation to another. Values were grouped in "Low", "Normal," and "High" sets in an attempt to bracket cost conditions which will be encountered within the study area (Table III-1). The combination of factors called "Normal", Case II, is the most representative of an overall average of current costs; the "Low" and "High" combinations, Cases I and III, respectively, are included to represent reasonable extremes.

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* Information as of 1968.

TABLE III-1

COST FACTORS

Case		Plant Capital Cost ($/KW)	Fixed Charge Rate (%)	Fuel Cost (¢/10^6Btu)	Land Cost ($/acre)
I	(Low)	110	11	25	250
II	(Normal)	135	14	30	500
III	(High)	160	17	35	1000
IV	(Normal-High Capital Cost)	160	14	30	500
V	(Normal-High Fixed Charge)	135	17	30	500
VI	(Normal-High Fuel Cost)	135	14	35	500
VII	(Normal-High Land Cost)	135	14	30	1000

Four additional sets of cost factors were used to show the effect of variation in individual factors as opposed to the combined effect of changing all factors from case to case. (See Table III-1, Cases IV-VII). In these cases, the "Normal" level of cost factors was used as a base except that one value from the "High" level was substituted in each of the four cases.

Information on cost components was obtained from numerous surveys, indexes and general references. Table III-2 presents sources and cost data by component category.

With this background, we can compute the basic plant cost for the seven combinations of economic factors cited in Table III-1. This information is presented in Table III-3 which gives the capital cost in dollars per KW and busbar cost in Mills per KWH. The busbar cost was calculated by summing up a constant operation and maintenance cost of .75 Mills/KWH with the fuel and fixed charge costs.

Differences in busbar costs between Cases I, II and III are brought about by changes in all of the first three cost factors (land costs are included for cooling pond analysis only -- the cost of land for the plant itself is included in the plant capital cost). As shown in Table III-4, Cases IV-VI are used to determine the busbar cost differences due to changes in individual cost factors. These data provide the basis for a later comparison of the added cost of specific cooling systems to other economic factors influencing generation cost.

TABLE III-2

COSTS AND REFERENCES

Source	Cost Data			
	Plant (Fossil) ($/KW)	Fixed Charge (%)	Fuel (¢/106 Btu)	Land ($/acre)
Short (III-10)	117	11-13		
Electrical World (III-1)	118	14	25	
Federal Power Commission (III-4,5)	105-186a/	104%b/	26.1	
Federal Power Commission (III-5)			28.9c/	
R. W. Beck (III-9)			30a/	
U. S. Dept. of Commerce (III-12)				206-1238a/
Edison Electric Institute (III-3)	97%b/		25.5a/	
Kempf & Fletcher (III-7)				200-6000
Swengel (III-11)	126	13.55	24.2	
National Coal Assoc. (III-8)			25.5a/	
WRC Advisory Committee (III-13)			26.4a/	

a/ Specific to States around Lake Michigan.
b/ States around Lake Michigan compared to U.S. average -- based on index values.
c/ Based on 10 plants currently using Lake Michigan for cooling.

TABLE III-3

BASIC PLANT COSTS
(Once-Through Cooling)

Case	Fixed Charges[a/] (Mills/KWH)	Operating Costs Fuel[b/] (Mills/KWH)	Operating Costs O & M[c/] (Mills/KWH)	Total Capital Cost ($/KW)	Busbar Cost (Mills/KWH)
I	1.69	2.13	0.75	110	4.57
II	2.63	2.56	0.75	135	5.94
III	3.79	2.99	0.75	160	7.53
IV	3.12	2.56	0.75	160	6.43
V	3.20	2.56	0.75	135	6.51
VI	2.63	2.99	0.75	135	6.37
VII	2.63	2.56	0.75	135	5.94

a/ Based on 82 percent plant factor.
b/ Based on 40 percent nominal plant efficiency.
c/ Based on U. S. average (Reference III-5)

TABLE III-4

INFLUENCE OF INDIVIDUAL COST FACTORS ON BUSBAR COST

Cost Factor Item	Case No.	Difference from Case II (Normal)	Resulting Change in Busbar Cost, Mills/KWH
Plant Capital Cost	IV	\$25/KW	0.49
Fixed Charge Rate	V	3%	0.57
Fuel Cost	VI	5¢/10^6 Btu	0.43

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IV. ENGINEERING CONSIDERATIONS

Introduction

The initial requirements for approximating the size and performance of alternative cooling systems are the design meteorological and lake temperature data for the four geographical sections (Tables II-5 and 8). Based on these data and generalized cost estimates for system components and operation, component sizes and performance characteristics are determined via digital computer programs.

The procedure for designing each cooling device varied according to the sources of the computer programs. A computer program developed by the Dynatech Corporation was used as a primary means for analyzing wet cooling towers, cooling ponds and once-through systems (Reference IV-5). The Ceramic Cooling Tower Company provided computer runs for the design of power spray modules for cooling canal systems (Reference IV-2). Advanced design and cost data on mechanical and natural draft dry (Heller) cooling systems were obtained from R. W. Beck and Associates (Reference IV-9).

The Dynatech and R. W. Beck computer programs are the results of FWQA research contract efforts. Back-up data from in-house sources were provided on natural draft wet towers and cooling ponds. Supplementary cost data on wet towers were obtained from The Marley Company (Reference IV-3) and Research-Cottrell, Inc. (Reference IV-10). Dynatech's program also had some design data on dry systems. Cross-referencing and spot checks between Dynatech, R. W. Beck and in-house calculations were made to assure consistency and reasonable agreement of the results despite the varied approaches used in system design.

Descriptions of the analytical techniques used in calculating the sizes and performance of the cooling devices are not presented in this report. The reader is urged to consult appropriate references on the subject (References IV-1, 4-5, 7-8, 12).

General Optimization Procedure

All cooling systems perform most effectively at elevated water temperatures. Reduced pumping and fan power, shorter tower packing, and smaller pond surface areas can be achieved by increasing the inlet water temperature to the cooling system. The same temperature increase, however, adversely affects the efficiency of the power plant as it results in condensing the steam at a higher turbine backpressure, and thus increases the turbine heat rate. An economic optimization therefore involves the analysis of the two competing factors for the selection of the condensing steam temperature.

Another important factor in determining the size and cost of a cooling system (i.e., cooling device and condenser) is the approach temperature. For a wet cooling tower and spray canal, the approach is equal to the difference between the cold water temperature and the ambient wet-bulb temperature. The approach temperature for a cooling pond is equal to the difference between the outlet cold water temperature and the equilibrium pond temperature; and for a dry tower, it is equal to the difference between the outlet water and dry-bulb temperatures. The smaller the approach, the larger the cooling device's heat exchange surface and consequently the cost. The magnitude of the approach temperature also affects the operation of the power generation system. The smaller the approach, the more efficient the power generation because of the lower sink temperature.

<u>Dynatech Program</u>

In designing a particular cooling system, Dynatech's computer program (Reference IV-5) optimizes with respect to both the approach and the condenser temperature. The calculations start with a minimum allowable condenser temperature. System costs are then calculated for all allowable approaches in increments of 1°F. This process is repeated for all allowable condenser temperatures, increasing the latter in each trial by 1°F. In this manner, the costs for all combinations of approach and condenser temperatures are calculated. The minimum cost that is found in this process gives rise to the "optimum" combination of approach and condenser temperatures for the design meteorological conditions.

In addition to size and performance data, the computer program provides capital system cost and total operating cost for the design conditions. An adjusted total operating cost estimate based on the off-design ambient meteorologic data (i.e., annual operation) and various plant capacities is also given. All seven combinations of economic factors presented in Table III-1 were used in the analysis for this report.

Dynatech's computer program has two options for specifying the plant capacity factor. One is a straight 100 percent capacity factor implying full-load year-round operation of the plant, and the other is a variable capacity operation over an annual cycle. The latter option was used here with an average yearly capacity factor of 82%. The selected capacity distribution throughout an annual cycle is as follows:

Capacity	1.00	.80	.60	.25	0
Hours/year	5150	1750	800	700	360

These data are needed for determining the yearly operating cost of the selected cooling system.

Another important system cost factor is the turbine heat rate and its variation with capacity factor and the condenser operating temperature. Data for a typical GE turbine of a 1000 MW capacity were used with the Dynatech program. Turbine heat rates at several capacity factors were obtained from the manufacturer's heat rate tables (Reference IV-6). At 1" Hg turbine backpressure and a capacity factor of 100 percent, the turbine heat rate is 7415 Btu/KWH; at 25 percent capacity it is 8807 Btu/KWH. (Note that the above are heat rates for a specific turbine and should not be equated to an overall plant heat rate). The Dynatech program has an interpolating routine that evaluates the heat rate at the plant capacity factor for the baseline design conditions*. Other heat rates are needed for the off-design* operating conditions, since it is necessary to calculate the total heat rejected at various capacities. From the heat rejection data and the percent of time the plant operates at off-design conditions, an estimate of the cooling system operating cost and the associated fuel savings can be made.

The off-design spring, summer, fall, and winter conditions were matched with the power plant capacity to allow maximum plant output during the summer and winter peaks. Table IV-1 shows the percent of time the cooling systems operate for various plant capacities.

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*The baseline design weather conditions and lake temperatures are given in Tables II-5 & II-8, respectively. Off-design conditions are given in Tables II-2 and II-7.

TABLE IV-1

PERCENT OF COOLING SYSTEMS TIME AT OFF-DESIGN CONDITIONS

Plant Capacity, %	Spring	Summer	Fall	Winter
100	10	40	10	40
80	15	35	15	35
60	35	15	35	15
25	40	10	40	10
0	0	0	100	0

These data are used in conjunction with the seasonal weather data (Tables II-2 and II-7) to compute annual operating costs for the chosen cooling system. The effect of more favorable off-design weather conditions gives average operating costs (in Mills/KWH) substantially lower than the operating costs under design conditions.

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In the course of the present studies, it was found that during extremely cold winter conditions, the cooling system did not receive adequate heat to prevent it from freezing. In practice, the flow rate can be changed to prevent this, or, in the case of cooling towers, ice rings for natural draft or fan reversal for mechanical draft towers can be used. It may even be advantageous to burn more fuel and generate greater quantities of electric power. No such provisions were made in Dynatech's program. For this reason, the cost data based on the variable ambient conditions may be too high. The 5 percent summer design data imposed severe operating conditions for tower design with the result that the cooling systems were "too good" during the winter off-design conditions.

For mechanical draft wet tower cooling systems the capital cost data developed by the Dynatech program agrees reasonably with 1970 published and unpublished information available from The Marley Company (Reference IV-3) and Fluor Corporation (Reference IV-11), two major tower manufacturers in the United States.

The total system cost for the natural draft towers presented in the following section of this report may not be minimal. Research-Cottrell (Reference IV-10) supplied current capital cost data, which checked favorably with that published by The Marley Company (Reference IV-3). However, this capital cost, which was inserted into the program, is based on a tower height of 500 feet and a tower diameter of 400 feet.

Thus, the optimization process became somewhat artificial. In particular, the approach temperature had to be fixed so that the tower size would be appropriate for the capital cost provided by Research-Cottrell. Hence, the operating cost portion of the total system cost may be inflated.

In determining the capital cost of a cooling pond, the Dynatech program simply multiplies the pond size (acres) by the land cost ($/acre). Thus, no land preparation or construction costs are included.

Ceramic Cooling Tower Program*

For this study, design data for spray cooling canals using Power Spray Modules (PSM) were supplied by the Ceramic Cooling Tower Company*. The output from the Ceramic program includes the number of Power Spray Modules, the minimum canal dimensions, and module cost.

As a part of the input data required for Ceramic Cooling Tower's computer program, the heat load, the water flow, the cooling range, and the outlet water temperature are all specified. These data were obtained from a cooling pond cooling system designed by the Dynatech program. Additional input data requirements include dry- and wet-bulb temperature, wind velocity, and barometric pressure.

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*The use of this program does not imply endorsement of the product by FWQA.

Other assumptions for complete cost evaluation of spray canals follow:

1. The condenser system cost was obtained as calculated from the Dynatech cooling pond system optimization.

2. The capital cost of the cooling canal system includes 15 percent of the material cost for installation and electrical work. The cost of the land and canal preparation was assumed at 12 percent of the material cost. The land cost was less than 1 percent, a very small cost item compared to cooling ponds.

3. The operating cost was based on the baseline design conditions with adjustments made for cooler temperatures. An adjustment factor of 0.62 was calculated based on the number of units in operation during spring, summer, and fall conditions. A maintenance cost equal to 1 percent of the operating cost was added, consistent with Dynatech's calculations.

4. The sum of the condenser system cost, the amortized capital cost and O & M cost made up the total system cost. No differential fuel cost was included, because it was assumed that the differential heat rate of a plant with a PSM system could be minimized by operating adequate number of units as the ambient conditions change.

R. W. Beck Program

R. W. Beck's computer program optimizes the dry system based on four major cost items -- capital cost, auxiliary power cost, cost due to loss of capacity, and fuel cost. Parametric study of all cost items are considered for initial temperature differences (ITD) between the inlet dry-bulb air and the inlet hot water temperatures ranging from 30°F to 80°F. At large initial temperature differences, the cooling system is highly efficient and thus compact and relatively inexpensive. The auxiliary power requirements are also relatively small. On the other hand, the loss of power and the resulting fuel cost are great. Thus, the last two cost items compete for the low ITD while the first two compete for the high ITD. The optimal ITD for a given region is consequently dictated by the combined effects of all cost factors.

R. W. Beck's program was run for four sites around Lake Michigan in order to show the effects of weather variations. These sites were Chicago, Green Bay, Milwaukee, and Grand Rapids. A total of 7500 hours per year of operation was assumed. One-half of this time was at 100 percent capacity and the other half at 75 percent capacity. The remaining 1260 hours per year were for shutdown.

The fuel cost and the fixed charge rates from Table III-1 were used. Whenever there occurred a loss of capacity of 10 hours per year or more at full throttle, gas turbine peaking units were used to make up for this loss. The loss of capacity at full throttle is due to high backpressure that may occur at peak demands. The cost of gas turbine peaking unit was assumed at $100/KW.

Both natural and mechanical draft dry towers were considered for all regions. The optimum tower dimensions and all cost items were output from the program.

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V. RESULTS

Performance data for the various alternative cooling systems are presented in Section A below. Cooling system cost includes the cost of condenser, pumps, piping, and controls, as well as the specified heat dissipation device. Comparative capital and busbar costs for the complete power plant using these alternative cooling systems are examined in Section B.

A. Cooling Systems

Introduction

For each cooling system, engineering performance data and capital and total system cost data are presented in tabular form. Since most of the data are self-explanatory, only limited descriptions of the tables are given.

Wet Cooling Towers

Performance Data

Mechanical Draft

A complete set of performance data for the mechanical draft wet cooling tower operating under design conditions is given in Table V-1 for each case and for the four sections of the Lake Michigan area. There appears to be little sectional variation.

All temperature values are rounded to within one degree. For this reason, one cannot expect to exactly recalculate the heat rejected by multiplying the range by the condenser flow.

TABLE V-1

PERFORMANCE DATA FOR A MECHANICAL DRAFT WET COOLING TOWER SYSTEM
AT DESIGN CONDITIONS

Case*	Section	Fan Power 10^3 hp	Cond. Flow 10^8 lb/hr	Cond. Flow cfs	Q_{REJ} 10° Btu/hr	H_2O Evap cfs	Air Flow 10^8 lb/hr	Range °F	Approach °F	Cond. Temp. °F
I	NE	2.20	2.26	1010	4.24	15.9	1.39	19	16	111
	SE	2.25	2.27	1010	4.25	16.1	1.40	19	15	112
	SW	2.13	2.28	1020	4.27	16.2	1.37	19	15	113
	NW	1.75	2.39	1060	4.24	15.8	1.32	18	18	111
	AVERAGE	2.08	2.30	1020	4.25	16.0	1.37	19	16	112
II	NE	2.23	2.16	962	4.25	16.0	1.36	20	16	112
	SE	1.96	2.28	1020	4.27	16.1	1.33	19	16	113
	SW	2.16	2.17	966	4.28	16.3	1.34	20	15	114
	NW	1.79	2.27	1010	4.25	15.9	1.29	19	18	112
	AVERAGE	2.04	2.22	988	4.26	16.1	1.33	20	16	113
III	NE	1.95	2.16	962	4.27	16.0	1.29	20	17	113
	SE	1.99	2.17	966	4.28	16.2	1.30	20	16	114
	SW	1.88	2.18	971	4.30	16.3	1.27	20	16	115
	NW	1.82	2.16	962	4.27	15.9	1.26	20	18	113
	AVERAGE	1.91	2.17	966	4.28	16.1	1.28	20	17	114
IV	NE	1.95	2.16	962	4.27	16.0	1.29	20	17	113
	SE	1.99	2.17	966	4.28	16.2	1.30	20	16	114
	SW	2.16	2.17	966	4.28	16.3	1.34	20	15	114
	NW	1.79	2.27	1010	4.25	15.9	1.29	19	18	112
	AVERAGE	1.97	2.19	975	4.27	16.1	1.31	20	17	113
V	NE	1.72	2.17	966	4.28	16.0	1.23	20	18	114
	SE	2.01	2.07	922	4.30	16.2	1.27	21	16	115
	SW	1.90	2.08	926	4.31	16.3	1.24	21	16	116
	NW	1.84	2.07	922	4.28	16.0	1.23	21	18	114
	AVERAGE	1.87	2.10	935	4.29	16.1	1.24	21	17	115

* See Table III-1

TABLE V-1 (Cont.)

PERFORMANCE DATA FOR A MECHANICAL DRAFT WET COOLING TOWER SYSTEM
AT DESIGN CONDITIONS

Case*	Section	Fan Power 10^3 hp	Cond. Flow 10^8 lb/hr	Cond. Flow cfs	Q_{REJ} 10° Btu/hr	H_2O Evap cfs	Air Flow 10^8 lb/hr	Range °F	Approach °F	Cond. Temp. °F
	NE	2.20	2.26	1010	4.24	15.9	1.39	19	16	111
	SE	2.25	2.27	1010	4.25	16.1	1.40	19	15	112
VI	SW	2.46	2.27	1010	4.25	16.2	1.44	19	14	112
	NW	2.32	2.26	1010	4.22	15.8	1.42	19	16	110
	AVERAGE	2.31	2.27	1010	4.24	16.0	1.41	19	15	111
	NE	2.23	2.16	962	4.25	16.0	1.36	20	16	112
	SE	1.96	2.28	1020	4.27	16.1	1.33	19	16	113
VII	SW	2.16	2.17	966	4.28	16.3	1.34	20	15	114
	NW	1.79	2.27	1010	4.25	15.9	1.29	19	18	112
	AVERAGE	2.04	2.22	988	4.26	16.1	1.33	20	16	113

* See Table III-1

Natural Draft

Table V-2 presents the performance data for wet natural draft towers operating under design conditions. Little variation between the four geographical sections was found, so the data are averaged over all sections.

System Cost

Mechanical Draft

Table V-3 presents the total capital cost and average cooling system cost rate for the wet mechanical draft towers described in Table V-1.

Natural Draft

Table V-4 presents the total capital cost and average cooling system cost rate for the wet natural draft cooling towers described in Table V-2. As mentioned previously, a tower capital cost of $6.50/KW is assumed for all cases. It should be specifically noted again that fixing the approach on the one hand and the tower cost on the other hand severely limits the cost optimization process. Thus, the total cooling system operating cost given is probably not minimal. This point is particularly stressed here for the comparison with the smaller costs for wet mechanical tower cooling systems.

TABLE V-2

PERFORMANCE DATA FOR NATURAL DRAFT WET COOLING TOWER
AT DESIGN CONDITIONS

Case *	Tower Height ** Ft.	Condenser Flow 10^8 lb/hr	cfs	$Q_{Rejected}$ 10^9 Btu/hr	Water Evaporated cfs	Air Flow 10^8 lb/hr	Range °F	Approach °F	Condenser Temp., °F
I	536	1.91	850	4.24	16.1	1.54	23	12	112
II	523	1.83	815	4.26	16.1	1.50	24	12	113
III	511	1.77	788	4.28	16.2	1.47	25	12	114
IV	511	1.77	788	4.28	16.2	1.47	25	12	114
V	502	1.72	766	4.29	16.2	1.44	25	12	114
VI	536	1.91	850	4.25	16.1	1.54	23	12	112
VII	523	1.83	815	4.26	16.1	1.50	24	12	113

* See table III-1

** Base diameter ≈ (Height/1.25)

TABLE V-3

COST DATA FOR MECHANICAL DRAFT WET COOLING TOWER SYSTEMS

Case*	Section	Condenser & Pump Cost, $/KW	Capital Cost of Tower, $/KW	Total System Capital Cost, $/KW	Total System Cost Mills/KWH
I	NE	5.87	2.85	8.72	0.178
	SE	5.89	2.94	8.83	0.179
	SW	5.91	2.89	8.80	0.179
	NW	6.03	2.55	8.58	0.177
	AVERAGE	5.93	2.81	8.74	0.178
II	NE	5.74	2.83	8.57	0.221
	SE	5.91	2.76	8.67	0.225
	SW	5.78	2.86	8.64	0.223
	NW	5.89	2.54	8.43	0.221
	AVERAGE	5.83	2.75	8.58	0.223
III	NE	5.76	2.66	8.42	0.271
	SE	5.78	2.73	8.51	0.273
	SW	5.80	2.69	8.49	0.274
	NW	5.76	2.53	8.29	0.269
	AVERAGE	5.78	2.65	8.43	0.272
IV	NE	5.76	2.66	8.42	0.225
	SE	5.78	2.73	8.51	0.227
	SW	5.78	2.86	8.64	0.228
	NW	5.89	2.54	8.43	0.226
	AVERAGE	5.80	2.70	8.50	0.227
V	NE	5.78	2.49	8.27	0.260
	SE	5.66	2.71	8.37	0.260
	SW	5.68	2.67	8.35	0.261
	NW	5.64	2.52	8.16	0.256
	AVERAGE	5.69	2.60	8.29	0.259

* See Table III-1

Continued

TABLE V-3 (Cont.)

COST DATA FOR MECHANICAL DRAFT WET COOLING TOWER SYSTEMS

Case*	Section	Condenser & Pump Cost, $/KW	Capital Cost of Tower, $/KW	Total System Capital Cost, $/KW	Total System Cost Mills/KWH
	NE	5.87	2.85	8.72	0.234
	SE	5.89	2.94	8.83	0.235
VI	SW	5.89	3.07	8.96	0.237
	NW	5.86	2.91	8.77	0.232
	AVERAGE	5.88	2.94	8.82	0.235
	NE	5.74	2.83	8.57	0.221
	SE	5.91	2.76	8.67	0.225
VII	SW	5.78	2.86	8.64	0.223
	NW	5.89	2.54	8.43	0.221
	AVERAGE	5.83	2.75	8.58	0.223

* See Table III-1

TABLE V-4

COST DATA FOR NATURAL DRAFT
COOLING TOWER SYSTEMS

Case*	Condenser & Pump Capital Cost,$/KW	Total System Capital Cost, $/KW	Total System Cost Mills/KWH
I	5.40	11.90	0.241
II	5.31	11.81	0.306
III	5.21	11.71	0.373
IV	5.21	11.71	0.310
V	5.14	11.64	0.358
VI	5.40	11.90	0.314
VII	5.30	11.80	0.306

* See Table III-1

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Cooling Ponds

Only flow-through ponds are examined in detail. Mixed pond sizes were not determined, however it is estimated that with proper selection, their areas would be about two to three times greater than the flow through ponds.

Performance Data

Flow-through cooling pond sizes and other parameters vary little from one section of the lake to another because of the small variations in the design ambient conditions. For example, there is less than 4 percent variation among the sizes in the four sections corresponding to Case I. Therefore, Table V-5 presents the average performance data for the four geographical sections. Optimum pond size is strongly influenced by the land cost as indicated in Table V-5. It varies from 2030 acres for a land cost of $500 per acre in Case II to 1490 acres for a land cost of $1000 per acre in Case VII.

System Cost

Table V-6 gives the total capital and average cooling system cost rates for flow-through cooling ponds. Variations in the cost of the cooling system between the four geographical sections are also shown.

TABLE V-5

COOLING POND PERFORMANCE DATA AT DESIGN CONDITIONS

Case*	Pond Size, Acres	Water Evap. cfs	Q_{REJ} 10^9 Btu/hr	Equilibrium Temp., °F	Hot Water Temp., °F	Range °F	Condenser Flow cfs
I	2140	40.8	4.21	86	104	17	1090
II	2030	39.3	4.23	86	106	19	1010
III	1470	32.2	4.26	86	108	19	1000
IV	2030	39.3	4.23	86	106	19	1010
V	1740	35.7	4.26	86	108	20	950
VI	2100	40.3	4.22	86	105	18	1060
VII	1490	32.5	4.25	86	107	19	1030

* See Table III-1

TABLE V-6

COST DATA FOR COOLING POND SYSTEMS

Case*	Section	Condenser & Pump Cost $/KW	Pond Capital Cost, $/KW	Total System Capital Cost $/KW	Total System Cost, Mills/KWH
I	NE	6.02	0.53	6.55	0.110
	SE	6.08	0.53	6.61	0.111
	SW	6.19	0.53	6.72	0.113
	NW	6.06	0.55	6.61	0.111
	AVERAGE	6.09	0.54	6.63	0.111
II	NE	5.88	1.03	6.91	0.148
	SE	5.94	1.02	6.96	0.149
	SW	5.90	1.00	6.90	0.148
	NW	5.78	1.02	6.80	0.145
	AVERAGE	5.88	1.02	6.90	0.148
III	NE	5.91	1.38	7.29	0.193
	SE	5.82	1.55	7.37	0.194
	SW	5.92	1.57	7.49	0.197
	NW	5.82	1.37	7.19	0.190
		5.87	1.47	7.34	0.194
IV	NE	5.88	1.03	6.91	0.150
	SE	5.94	1.02	6.96	0.151
	SW	5.90	1.00	6.90	0.150
	NW	5.78	1.02	6.80	0.147
	AVERAGE	5.88	1.02	6.90	0.150

* See Table III-1

Continued

TABLE V-6 (Cont.)

COST DATA FOR COOLING POND SYSTEMS

Case*	Section	Condenser & Pump Cost $/KW	Pond Capital Cost, $/KW	Total System Capital Cost $/KW	Total System Cost, Mills/KWH
	NE	5.76	0.79	6.55	0.171
	SE	5.68	0.96	6.64	0.172
V	SW	5.77	0.96	6.73	0.175
	NW	5.67	0.78	6.45	0.168
	AVERAGE	5.72	0.87	6.59	0.172
	NE	6.02	1.07	7.09	0.153
	SE	6.08	1.05	7.13	0.154
VI	SW	6.04	1.03	7.07	0.152
	NW	5.92	1.05	6.97	0.150
	AVERAGE	6.02	1.05	7.07	0.152
	NE	5.91	1.38	7.29	0.157
	SE	5.96	1.60	7.56	0.162
VII	SW	5.92	1.57	7.49	0.161
	NW	5.95	1.41	7.36	0.159
	AVERAGE	5.94	1.49	7.43	0.160

* See Table III-1

Spray Cooling Canals

Performance Data

Performance data for spray cooling canals using Ceramic Cooling Tower Company's Power Spray Module are given in Table V-7. The input data were selected from the cooling pond design information given in Table V-5. As indicated in Table V-7, the PSM's are arranged in rows of four units across the canal, with from 28 to 32 rows spread along the canal's length. Thus, water flowing down the canal will be cooled as it passes through consecutive rows of PSM units.

System Cost

The average total material cost for the spray cooling canals described in Table V-7 is \$1.83/KW. Further additional costs, as described previously in Section IV - "Engineering Considerations" - increase the total capital cost (exclusive of condenser system) to \$2.30/KW. Table V-8 presents the spray cooling canal cost data.

Dry Cooling Towers (Heller System)

Performance Data

The optimal initial temperature difference (ITD) for all sites examined ranged from 57 to 62°F. For these ITD's, the optimal water cooling range is on the order of 50 percent of the corresponding ITD.

TABLE V-7

SPRAY COOLING CANAL PERFORMANCE DATA AT DESIGN CONDITIONS

Parameter	Section NW	SW	SE	NE
Approach, ^oF	20	16	17	19
Range, ^oF	20	20	20	20
Cold Water Temp., ^oF	90	90	90	90
Condenser Flow, cfs	960	960	960	960
Heat rejected, 10^9 Btu/hr	4.3	4.3	4.3	4.3
Total number of PSM-4-10-75	112	128	124	116
Number of units per row	4	4	4	4
Number of rows	28	32	31	29
Total Horsepower	8400	9600	9300	8700
Minimum channel width, ft.	160	160	160	160
Minimum channel length, ft.	4480	5120	4960	4640

TABLE V-8

COST DATA FOR SPRAY CANAL COOLING SYSTEMS

Case*	Condenser & Pump $/KW	Spray Canal $/KW	Total Capital Cost, $/KW	Total System Cost, Mills/KWH
I	6.09	2.30	8.39	0.148
II	5.88	2.30	8.18	0.185
III	5.87	2.30	8.17	0.225
IV	5.88	2.30	8.18	0.185
V	5.72	2.30	8.02	0.216
VI	6.02	2.30	8.32	0.189
VII	5.95	2.30	8.25	0.185

* See Table III-1

The land requirement for a mechanical draft tower at ITD = 57°F is 8.7 acres and at ITD = 62°F is 7.8 acres.

The size of a natural draft tower varies with the initial temperature difference, being smaller when the ITD is large. The height, base diameter, and the top diameter date at the two extreme ITD's are listed in Table V-9 below:

TABLE V-9

DIMENSIONS OF NATURAL DRAFT COOLING TOWER IN FEET

Dimension	ITD = 57°F	ITD = 62°F
Height	487	455
Base diameter	593	547
Top diameter	398	383

Cooling System Cost

Capital Cost

The range of capital cost for a mechanical draft dry cooling tower system for Chicago is listed below:

ITD °F	58-59
Cost without peaking, $/KW	16.8 - 17.1
Cost with peaking, $/KW	24.0 - 24.1

The capital cost of a natural draft dry tower depends on the size of the tower. Additional cost for peaking units is included whenever a substantial loss in capacity occurs. Gas turbine peaking units were chosen at an assumed cost of $100/KW. The total capital cost is the sum of these two items. The range of capital costs of natural draft cooling towers for the sites examined are listed in Table V-10 as a function of optimal ITD's.

TABLE V-10

COOLING SYSTEM CAPITAL COST ($/KW) OF NATURAL DRAFT DRY COOLING TOWER

Site	ITD °F	Cost without Peaking ($/KW)	Cost with Peaking ($/KW)
Chicago	57-58	18.8 - 19.1	25.8 - 25.8
Grand Rapids	57-58	18.8 - 18.4	25.1 - 25.2
Milwaukee	58	19.7	26.8
Green Bay	58-62	18.5 - 19.7	25.4 - 25.5

System Cost

The total cost of the cooling system with mechanical draft dry cooling towers for the four sites examined are listed in Table V-11.

TABLE V-11

TOTAL SYSTEM COST DATA FOR MECHANICAL
DRAFT DRY COOLING TOWER SYSTEMS (MILLS/KWH)

Case*	Chicago	Green Bay	Milwaukee	Grand Rapids	Average
I	0.57	0.55	0.58	0.55	0.56
II	0.72	0.69	0.72	0.69	0.71
III	0.87	0.82	0.87	0.82	0.85
IV	0.72	0.69	0.72	0.69	0.71
V	0.85	0.82	0.84	0.81	0.83
VI	0.74	0.70	0.74	0.70	0.72
VII	0.72	0.69	0.72	0.69	0.71

* See Table III-1

The total costs of the cooling system with natural draft dry cooling towers for the four sites examined are listed in Table V-12.

TABLE V-12

TOTAL SYSTEM COST DATA FOR NATURAL
DRAFT DRY COOLING TOWER SYSTEMS (MILLS/KWH)

Case *	Chicago	Green Bay	Milwaukee	Grand Rapids	Average
I	0.54	0.52	0.54	0.51	0.53
II	0.67	0.64	0.68	0.64	0.66
III	0.80	0.77	0.82	0.77	0.79
IV	0.67	0.64	0.68	0.64	0.66
V	0.79	0.76	0.81	0.76	0.78
VI	0.68	0.65	0.69	0.65	0.67
VII	0.67	0.64	0.68	0.64	0.66

* See Table III-1

B. Economics of Cooling Systems and Total Plants

Total costs are presented which account for all components included in each cooling system. For the sake of comparing costs of alternate cooling systems, however, the cost in excess of the minimum requirement is most meaningful. The minimum cooling system requirement for this analysis is the once-through cooling system described earlier in Section III. Table V-13 shows the cost differential in capital cost ($/KW) and busbar cost (Mills/KWH) for the cooling systems designed for the various economic conditions defined by Cases I through VII.

The effect of cooling system choice on the total cost of producing power is shown in Table V-14 which summarizes total busbar costs for all plant-cooling system combinations studied. The busbar costs in Table V-14 include all fixed and variable cost components which are involved in the cost of the basic plant with once-through cooling, Table III-3, and the differential cooling system costs, Table V-13.

TABLE V-13

CAPITAL COST AND BUSBAR COST DIFFERENTIAL
(In Excess of Once-Through System)
($/KW and Mills/KWH)

Case*	Mechanical Draft Wet Tower		Natural Draft Wet Tower		Cooling Pond		Spray Canal		Mechanical Draft Dry Tower		Natural Draft Dry Tower	
	$/KW	Mills/KWH	$/KW	Mills/KWH	$/KW	Mills/KWH	$/KW	Mills/KWH	$/KW	Mills/KWH	$/KW	Mills/KWH
I	3.76	0.079	6.92	0.142	1.65	0.012	3.41	0.049	19.07	0.46	20.82	0.43
II	3.64	0.096	6.87	0.179	1.96	0.021	3.24	0.058	19.11	0.58	20.86	0.53
III	3.54	0.117	6.82	0.218	2.45	0.039	3.28	0.070	19.16	0.70	20.91	0.64
IV	3.61	0.099	6.82	0.182	2.01	0.022	3.29	0.057	19.16	0.58	20.91	0.53
V	3.49	0.108	6.84	0.207	1.79	0.021	3.22	0.065	19.25	0.68	21.00	0.63
VI	3.79	0.106	6.87	0.185	2.04	0.023	3.29	0.060	19.02	0.59	20.77	0.54
VII	3.64	0.096	6.86	0.179	2.49	0.033	3.31	0.058	19.11	0.58	20.86	0.53

*See Table II-1

TABLE V-14

TOTAL BUSBAR COSTS FOR STANDARD POWER PLANT* USING COOLING SYSTEM SPECIFIED
Mills/KWH

Case**	Once-Through	Mechanical Draft Wet Tower	Natural Draft Wet Tower	Cooling Pond	Spray Canals	Mechanical Draft Dry Tower	Natural Draft Dry Tower
I	4.57	4.65	4.71	4.58	4.62	5.03	5.00
II	5.94	6.04	6.12	5.96	6.00	6.52	6.47
III	7.53	7.65	7.75	7.57	7.60	8.23	8.17
IV	6.43	6.53	6.61	6.45	6.49	7.01	6.96
V	6.51	6.62	6.72	6.53	6.58	7.19	7.14
VI	6.37	6.48	6.56	6.39	6.43	6.96	6.91
VII	5.94	6.04	6.12	5.97	6.00	6.52	6.47

*Fossil-fueled,1000 MW electrical output, 40% nominal efficiency, 82% plant capacity factor (As defined in Section I).

** See Table III-1

VI. ENVIRONMENTAL EFFECTS OF COOLING DEVICES

Introduction

The areas of environmental concern associated with heat dissipation methods can be separated into four general categories:

1) Fog potential
2) Consumptive water loss by evaporation
3) Drift
4) Blowdown

A fifth category, "Effect on Local Weather," can also be considered, but this effect is closely related to number 1 above.

In terms of the alternative methods of heat dissipation discussed in this report, the above concerns may be associated with specific cooling devices as shown in Table VI-1.

It is apparent from Table VI-1 that dry cooling devices should have no adverse affect on the environment. In fact, it has been suggested by Stewart (Reference VI-23) that the heat from dry towers could be used beneficially to dissipate fog at airports.

TABLE VI-1

ENVIRONMENTAL EFFECTS OF COOLING DEVICES

Cooling Method	Environmental Effects			
	Potential Fog	Evaporation	Blowdown	Drift
Wet Towers	Yes	Yes	Yes	Yes
Ponds	Yes	Yes	No	No
Spray Canals	Yes	Yes	Yes	Yes
Dry Towers	No	No	No	No

Fog Potential

Definition of the Problem

Essentially, fog is a cloud at ground level and can be described as a collection of very small liquid water droplets (e.g., <50 micron diameter) suspended in the air. Fog exists only when the air is saturated with water vapor. Since cold air becomes saturated at a much lower water content than warm air, cold climates present a greater potential for fog. Thus, one need not worry about fog formation except under climatic conditions of high humidity and low temperature.

Wet cooling devices discharge water vapor to the atmosphere as a direct result of their primary heat exchange mechanism - evaporation. Under normal circumstances, this discharge of moisture-laden air is dissipated rapidly in the ambient air. However, under severe climatic conditions (i.e., high humidity and low temperature) the moisture could produce a fog condition if the moisture were trapped in the lower levels of the atmosphere, such as during a period of high atmospheric stability (i.e., an inversion).

Cooling towers do produce visible plumes. However, plumes are not a problem unless they reach the ground, thus causing fog. In fact, only when the fog occurs over inhabited areas would it be considered a problem. Special concern should be directed towards a fog which may cause obstruction of vision on highways or near airports. Downwash of the plume from an oil refinery's mechanical draft cooling tower caused such a problem on an adjacent highway during the winter of 1959 (Reference VI-11, see paper by Hall). The problem was solved by installing heaters in the tower stack, thus increasing the ability of the air to hold water vapor and prevent saturation conditions. This technique is described by Buss (Reference VI-5). Such problems should normally be prevented by siting a cooling tower as far from highways and airports as possible. Also, the tower should be located so it is downwind from the point of interest during periods of low temperature and high humidity.

Under normal conditions, cooling tower plumes rise due to their initial velocity and buoyancy and rarely intersect the ground before they are dissipated. The plumes also have the ability to penetrate through an inversion. Visual observations at the Keystone Plant near Shelocta, Pennsylvania, indicate that even under conditions of severe local ground fog, the plumes from the plant's cooling towers penetrated through the ground fog and were dissipated in the upper air.

Several publications are available (References VI-2-5, 11, 14, 20, 23, and 24) which deal with the fog potential of wet cooling towers. While it is generally agreed that cooling towers are potential fog producers, it is also generally agreed that they are not probable fog producers. Most authorities agree that low profile mechanical draft towers are more likely to produce a fog condition than tall, natural draft towers. However, at least one source (Reference VI-14) indicates that the initial height of the vapor emission is not important, but rather the concentration of the heat and water vapor in a single point (i.e., natural draft tower) rather than in a line source (i.e., mechanical draft towers) tends to provide greater opportunity for the plume to rise.

Very little information is available on the fog potential of cooling ponds. Decker (Reference VI-11) contends that "Pond cooling should provide the greatest change of fog formation at the surface," however, experience to date (Reference VI-20) indicates that this cold weather "steam fog" stays over the surface of the pond and does not create local fog problems. Winter icing can occur near the edges of the pond. Actually, one would not expect the fog conditions over a cooling pond to differ much from those over a once-through discharge area of a lake or river.

Environmental Studies

At least two reports (References VI-4 and 20) deal with site visits to large U. S. power plants which utilize wet towers. One report was prepared by a utility (Reference VI-4), the other by State and Federal pollution control agencies (Reference VI-20). Both study teams visited plants in the coal mining region of the Appalachian Mountains, i.e., Keystone, Fort Martin, Big Sandy, and Clinch River. The pollution control agency team also visited the Mt. Storm plant which uses a cooling pond. The general conclusions of both reports are the same -- fog from the towers (and pond) was not considered a problem by the plant operators or by the local residents. A similar study conducted in Europe resulted in the same conclusion (Reference VI-11).

Of course, visits to sites and discussions with plant personnel can only give qualitative information as to the fog potential of cooling towers. A rigorous, scientific investigation is needed to provide firmer evidence. Such a study is being conducted at the Keystone plant by IIT Research Institute. The study's principal investigator, Dr. Eric Ansley, reports in a recent issue of Electrical World (Reference VI-2):

> "There is some apprehension today that cooling-tower emissions may produce undesirable environmental effects. Inadvertent weather effects, including local fogging and icing, cloud formation, and increased precipitation, are often cited as possibilities. Initial results from ground and aerial studies being conducted by IIT Research Institute of Chicago at the Keystone Generating Station indicate that no immediate problems appear to exist."

Thus, it appears that much of the talk about fog from cooling towers is not based upon what actually happens with existing installations. Of course, the fact that major problems have not yet come to light should not make us complacent as to the potential problem. Decker (Reference VI-11) concludes "...that except for extremely poorly-located cooling towers, the operators should encounter very little, if any, liability because of nuisance to neighbors." Therefore, detailed meteorological surveys should be made at the sites of all future large cooling tower installations where fog could be a potential problem.

Potential in Lake Michigan Area

E G & G has prepared a map, reproduced in Figure VI-1, showing the distribution of fog potential for the United States (Reference VI-14, page 38). According to E G & G, the "qualitative classification for the potential for adverse cooling tower affects" was made using the following criteria (Reference VI-14, page 36):

a) High Potential: Regions where naturally occurring heavy fog is observed over 45 days per year, where during October through March the maximum mixing depths are low (400-600m), and the frequency of low-level inversions is at least 20-30%.

b) Moderate Potential: Regions where naturally occurring heavy fog is observed over 20 days per year, where during October through March the maximum mixing depths are less than 600m, and the frequency of low-level inversions is at least 20-30%.

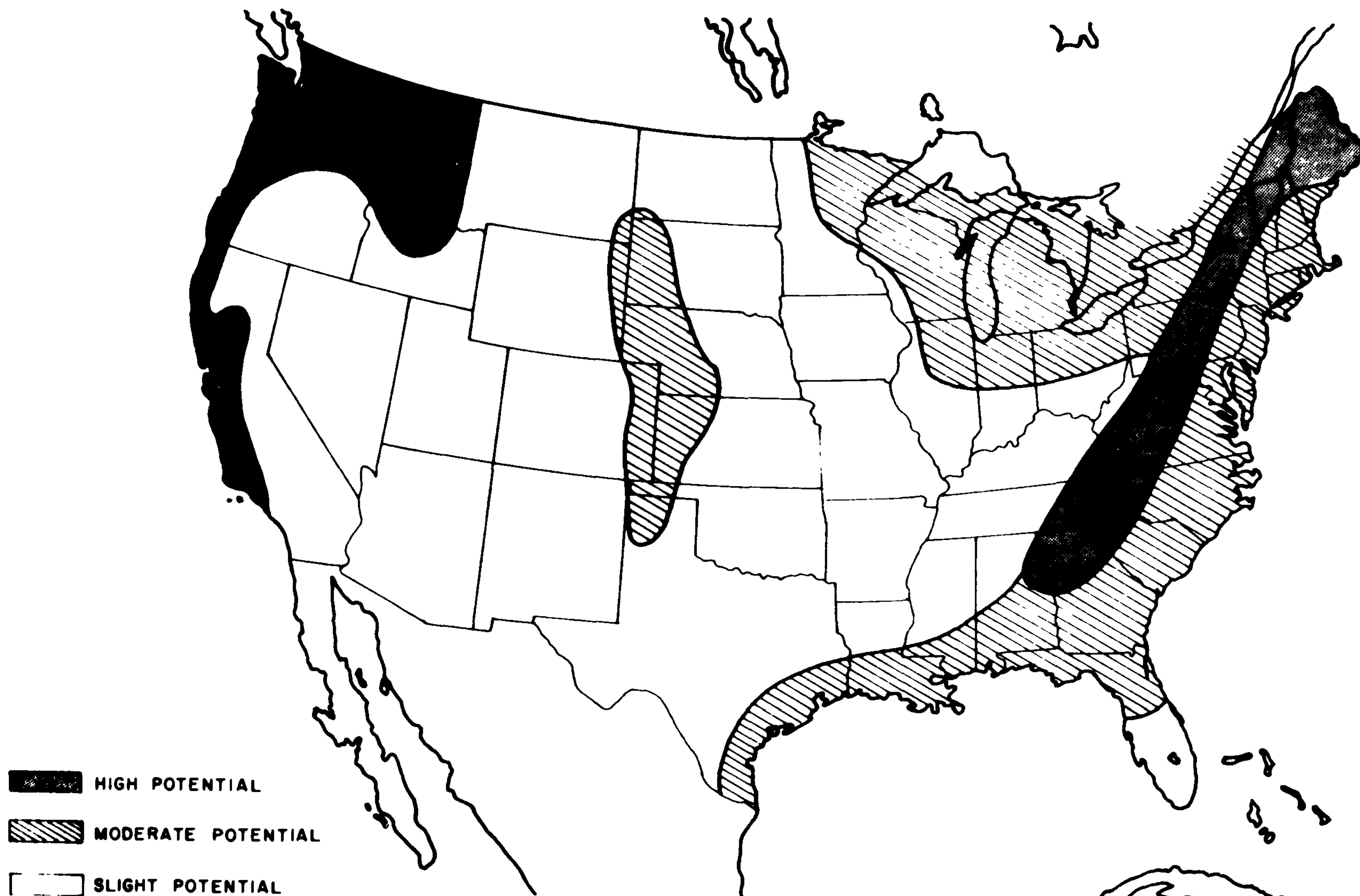

FIGURE VI-1 GEOGRAPHICAL DISTRIBUTION OF POTENTIAL ADVERSE EFFECTS FROM COOLING TOWERS, BASED ON FOG, LOW-LEVEL INVERSION AND LOW MIXING DEPTH FREQUENCY.

c) Low Potential: Regions where naturally occurring heavy fog is observed less than 20 days per year, and where October through March the maximum mixing depths are moderate to high (generally >600m).

As shown in Figure VI-1, Lake Michigan is located in an area of "moderate potential." Thus, some concern over potential fogging in this area seems justified. It must be emphasized, however, that the classifications of "high," "moderate," and "low" potential are relative rather than absolute descriptors. Thus, a cooling tower located in an area of "high potential" would be more likely to cause a fogging problem than one located in an area of "moderate" or "low potential," but whether or not the tower ever produced a fog problem would depend on specific site and climatic conditions. For example, the plants visited by the study teams mentioned previously were located predominantly in the "high potential" region of Figure VI-1 and no fogging problems were reported.

A study conducted by Travelers Research Corporation (Reference VI-24) to evaluate the climatic effects of a natural draft cooling tower for the proposed Davis-Besse Nuclear Plant at Locust Point on Lake Erie concluded that the visible plume will touch the ground only 2 percent of the time on an annual basis and that localized icing could occur at ground level approximately 3 percent of the time. No problems due to precipitation were anticipated. The results of this study, while specific to the Lake Erie site, give some indication that towers near Lake Michigan may have similar minor environmental effects due to similar weather conditions and because both areas lie in the same region of "moderate potential" indicated in Figure VI-1. This study is of special interest since Toledo Edison recently announced plans to use a natural draft wet tower at the Davis-Besse facility.

Calculations of Fog Potential

Two simplified methods are presented below for evaluating the fog potential of cooling towers in the vicinity of Lake Michigan.

Method 1

Fog is formed when the local humidity is raised to saturation. Thus, when cooling towers add water vapor to the atmosphere in quantities sufficient to cause saturation of the ambient air, fog will be produced.

The criterion for fog can be expressed as (Reference VI-14):

$$q_s - q_a \overline{<} \Delta q$$

where,

q_s = Liquid-water content at saturation, g/m^3

q_a = Liquid-water content of ambient air, g/m^3

Δq = Liquid-water added by cooling towers, g/m^3

E G & G (Reference VI-14) states that Δq is normally between 0.1 and 0.5 g/m^3 one or more kilometers downwind from the tower. Thus, any time $(q_s - q_a)$ is less than 0.1 to 0.5 g/m^3, there is a potential for fog conditions within one or two miles of the cooling tower.

Figure VI-2 presents plots of $(q_s - q_a)$ equal to 0.1 g/m^3 and 0.5 g/m^3 for various combinations of relative humidity and air temperature. Any combination of relative humidity and temperature falling in Zone C (i.e., $(q_s - q_a) > 0.5$ g/m^3) indicates weather conditions very unlikely to produce a cooling tower fog. This is true simply because the ambient air is able to assimilate more than 0.5 g/m^3 of water vapor without becoming saturated. Weather exhibiting temperatures and relative humidities in Zone B (i.e., 0.1 g/m^3 < $(q_s - q_a)$ < 0.5 g/m^3) has a low probability of producing a cooling tower fog, while a temperature-relative humidity combination falling in Zone A (i.e., $(q_s - q_a) < 0.1$ g/m^3) has a high probability of causing a fog condition when combined with a cooling tower air-water vapor effluent.

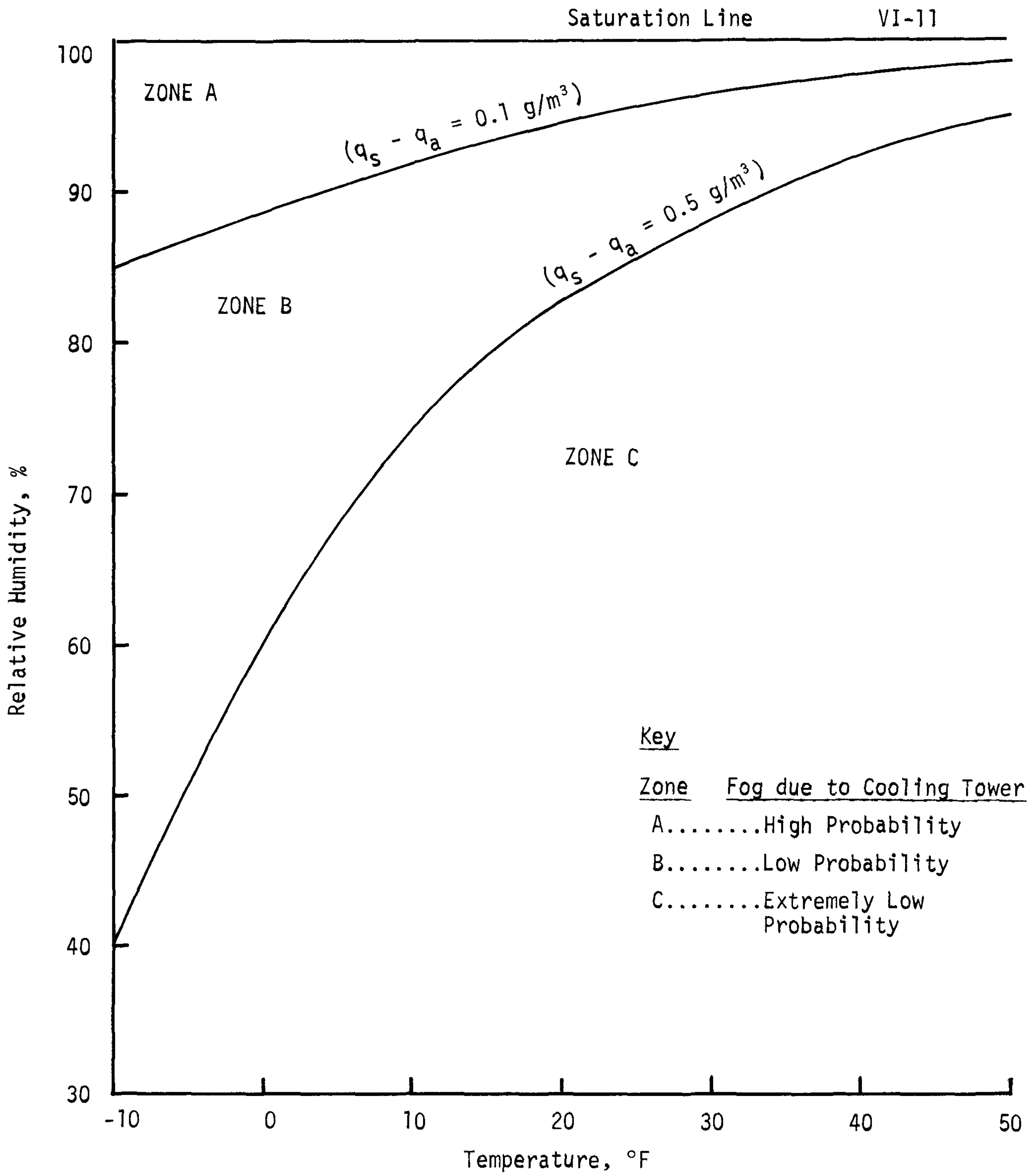

Figure VI-2: Plots of $(q_s - q_a) = 0.1$ and $0.5\ g/m^3$ for Relative Humidity versus Temperature

In order to determine the potential for cooling tower fog in a particular location, one should determine the total percent of time the weather conditions shown in the three zones of Figure VI-2 occur. Two stations in the Lake Michigan area are selected for such an analysis. Green Bay, Wisconsin is representative of the cold northern area and Chicago, Illinois is chosen to represent the more moderate climate of the south end of the Lake. Appropriate data were obtained from the U. S. Weather Bureau summaries of hourly observations (References VI-8 and 10).

Table VI-2 gives a breakdown of the percent of time over an annual cycle when the conditions in the three zones of Figure VI-2 occurred for four ranges of wind speed:

TABLE VI-2

PERCENTAGE OF TIME WEATHER CONDITIONS OCCURRED FOR ZONES A, B, AND C OF FIGURE VI-2

	Green Bay (North)			Chicago (South)		
Wind	Zone A	Zone B	Zone C	Zone A	Zone B	Zone C
<5 mph	0.2%	2.5%	97.3%	0.02%	0.6%	99.4%
<15 mph	0.7%	9.6%	89.7%	0.09%	3.3%	96.6%
<25 mph	0.8%	12.1%	87.1%	0.11%	4.1%	95.8%
All winds	0.9%	12.3%	86.8%	0.11%	4.2%	95.7%

Further separation of meteorological conditions by wind speed is included in Table VI-2 because high winds are more likely to provide ventilation to sweep fog away if it does form.

Weather data from Grand Rapids, Michigan (Reference VI-9) on the east side of the lake were also examined. Fog probabilities were found to be intermediate between those at Chicago and Green Bay.

Method 2

The necessity of assuming a value for Δq in the foregoing analytical method can be overcome by computing the dilution of a cooling tower plume with the ambient air. A simplified method of approximating the dilution of a cooling tower plume by the ambient atmosphere can be developed from standard methods of evaluating smoke plumes from a point source.

Turner (Reference VI-25) gives values of vertical and horizontal dispersion coefficients (σ_z, σ_y) for plumes as a function of downwind distance for several atmospheric stability categories. These coefficients can be used to estimate plume spread in the two cross-sectional dimensions of the plume, and thus the dilution of the plume with the ambient atmosphere is indicated.

Assuming no dilution for the first 100 meters downwind (this should be a very conservative assumption), one can estimate plume spread and plume dilution for values of x greater than 100 meters by the following equations:

$$\text{Vertical spread at } x_2 = \frac{\sigma_{z2}}{\sigma_{z1}}$$

$$\text{Horizontal spread at } x_2 = \frac{\sigma_{y2}}{\sigma_{y1}}$$

$$\text{Plume Dilution} = \frac{\sigma_{z2}\ \sigma_{y2}}{\sigma_{z1}\ \sigma_{y1}}$$

where,

x = Downwind distance

σ_{z1}, σ_{y1} = Dispersion coefficients at $x = 100$ meters

σ_{z2}, σ_{y2} = Dispersion coefficients at x_2

Tables VI-3,4 and 5 summarize the pertinent data from Reference VI-25. Note that stability classes A-F are indicated. Class A represents the most unstable condition where dilution and plume rise would be maximized. Stability increases from A to F, where Class F represents the most stable atmospheric conditions were dilution and plume rise would be minimal.

TABLE VI-3

DATA FROM FIGURES 3-2, 3-3, 4-1 IN TURNER (VI-25)

Downwind Distance (x) meters	Atmospheric Stability Class	Horizontal Dispersion (σ_y) meters	Vertical Dispersion (σ_y) meters	Cross-section Dispersion (σ_y, σ_z) square meters
100	A	27	10.4	400
	B	19	10.1	210
	C	12	7.4	94
	D	8	4.7	40
	E	6	3.5	22
	F	4	2.3	9
1000	A	210	450	100,000
	B	150	110	17,000
	C	105	60	6,200
	D	69	32	2,100
	E	50	22	1,100
	F	33	14	500
10,000	A	1050	>10,000	>2,000,000
	B	1020	1030	>1,000,000
	C	820	500	400,000
	D	560	130	82,000
	E	410	80	33,000
	F	270	46	12,500

TABLE VI-4

DILUTION RATIOS

X_2	Stability Class	Dilution Ratios
1,000 m	A	250
	B	81
	C	67
	D	53
	E	50
	F	56
10,000 m*	A	>5,000
	B	>4,700
	C	4,250
	D	2,050
	E	1,500
	F	1,390

*A somewhat more accurate estimate of the dilution rates at 10,000 m can be obtained by using the ratio of $\sigma_{y1}\ \sigma_{z1}/\sigma_{y2}\ \sigma_{z2}$, where x_1 = 1000 m and x_2 = 10,000 m and.multiplying the ratio by the dilution rate at x = 100 m. These are shown in Table VI-5.

TABLE VI-5

DILUTION RATIOS

X	Stability	Dilution Ratios
10,000 m	A	>8,000
	B	>12,000
	C	6,060
	D	1,560
	E	660
	F	225

To evaluate the amount of dilution required to prevent a cooling tower fog, one must have information on the ambient air temperature and relative humidity as well as the initial temperature of the tower plume which is assumed to be saturated.

Two cases are illustrated below:

<u>Case 1 - High Fog Potential</u>

Air Temperature = 0°F

Relative Humidity = 95%

Plume Temperature = 50°F (estimated)

Plume moisture = 9.4 g/m^3

Ambient air moisture = 1.21 g/m^3

Moisture in saturated 0°F air = 1.27 g/m^3

$\therefore$ Dilution (D) required:

$$9.4\ g/m^3 + 1.21\ g/m^3\ (D) = (1 + D)\ 1.27\ g/m^3$$

$$D = 136$$

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Therefore, one part tower effluent to more than 136 parts ambient air will not produce saturation. From Table VI-4, it is seen that at a downwind distance of 1000 meters insufficient dilution (i.e., $D < 136$) is obtained for stability Classes B, C, D, E, and F. These classes would produce a visible plume at that distance, and fog would be possible if the plume reached the ground, however, normally the plume would rise. The most unstable condition (e.g., Stability Class A) would provide adequate dilution. This trend corresponds to Reference VI-14 where it is concluded that more stable conditions provide greater fog potential. Table VI-5 indicates that at 10,000 meters dilution sufficient to prevent fog is present for all stability categories.

Case 2 - Low Fog Potential

Air Temperature = 50°F

Relative Humidity = 95%

Plume Temperature = 80°F (estimated)

Plume moisture = 25.3 g/m^3

Ambient air moisture = 8.9 g/m^3

Moisture in saturated 50°F air = 9.4 g/m^3

$\therefore$ Dilution required:

$$25.3 \text{ g/m}^3 + 8.9 \text{ g/m}^3 (D) = (1 + D)\ 9.4 \text{ g/m}^3$$

$$D = 32$$

Since Table VI-4 indicates dilution rates in excess of 32 for all stability classes, a visible plume at 1000 meters downwind would not exist and fog would not be possible.

It should be emphasized that the above analyses (i.e., Methods 1 and 2) are very general and unsophisticated. However, they do indicate that weather conditions in the Lake Michigan area are seldom severe enough to cause extensive fog conditions in the vicinity of wet cooling devices.

A more sophisticated approach to analyzing the potential for adverse weather effects due to cooling towers was developed by E G & G under an FWQA contract (Reference VI-14). However, the mathematical model constructed by E G & G is only useful in analyzing specific sites with specific meteorological data. It would be impractical to generalize the model to run cases applicable to this Lake Michigan study. It should be emphasized, therefore, that for proposed specific power plant sites, adequate meteorological data should be collected during the site selection phase so that accurate predictions of the fog potential of cooling towers at these sites can be made.

Consumptive Water Loss by Evaporation

Heat transfer by evaporation is one of the principal mechanisms by which wet cooling systems dissipate waste heat to the atmosphere. Thus, transfer of mass occurs and is a factor in the Lake Michigan water budget.

The present average water budget is approximately characterized by precipitation of 50,000 cfs, tributary inflow of 39,000 cfs, evaporation of 40,000 cfs, diversion at Chicago of 3,400 cfs, and discharge at the Straits of Mackinac of 46,000 cfs (References VI-1 and 17).

Hauser and Oleson (Reference VI-15) compared the evaporation losses of several wet cooling systems. They (Figure 2 of Reference VI-15) estimated evaporation rates as reflected in Table VI-6 given the following meteorological and design conditions:

Wet bulb temperature	=	70°F
Relative humidity	=	60%
Cloud cover	=	7/10
Wind speed	=	8 mph
Cooling range	=	20°F

It must be emphasized that the data in Table VI-6 are representative of <u>specific</u> meteorological and plant operating conditions and thus they cannot be applied to the cooling system designs presented here for Lake Michigan. However, the data in Table VI-6 do give order of magnitude estimates useful in determining the relationship between the evaporation rates for various cooling methods.

TABLE VI-6

BASED ON DATA FROM HAUSER AND OLESON (REFERENCE VI-15)

Cooling System	Evaporation cfs[1]
Cooling Pond (2 acres/MW)	20.0
Cooling Pond (1 acre/MW)	16.0
Mechanical Draft Tower	13.0
Spray Pond	12.7
Natural Draft Tower	12.0
Natural Lake or River	9.4

[1]For a 1000 MWe fossil fueled plant at 82 percent capacity factor average annual evaporation (assume constant meteorological conditions).

Data on rates of evaporation loss for the various wet cooling devices at summertime design meteorological conditions are presented in Section V, "Results," in Tables V-1, V-2, and V-5. To obtain data meaningful in terms of the annual water budget, one must adjust these values to reflect 1) lower evaporation rates during the off-design conditions, and 2) plant operation at less than 100 percent capacity.

The average annual evaporation rate for the wet towers and spray canals are approximated by multiplying the rate under design conditions by the plant capacity factor (0.82) and by 0.8 to reflect an average decrease in evaporation rate of 20 percent during the off-design period.

Cooling ponds experience a much more pronounced drop in evaporation during the off-design period (i.e., annual cycle) because of a large decrease in the incoming long and short wave radiation. For example, the design incoming radiation equals 5580 Btu/ft^2 day, while for the normal annual cycle it averages 3070 Btu/ft^2 day. Thus, during off-design conditions averaged over the year the pond dissipates approximately 2500 Btu/ft^2 day less energy. In terms of evaporative loss this is equivalent to 10 cfs per 1000 acres of pond surface. This factor along with the plant capacity factor (0.82) is used to calculate annual evaporation rates from design condition evaporation rates.

Table VI-7 presents the evaporation rates for both the design case and average annual conditions for the appropriate cooling devices. The data given in Table VI-7 represent the evaporation rates averaged over the four geographic sections since little variation was found between these sections. The average evaporation rates for all seven cases is also given.

In evaluating the consumptive water loss for cooling ponds, the natural evapo-transpiration losses of the area should be considered. The Lake Michigan region has an average annual precipitation rate of 30-inches per year (Reference VI-7) and an average annual runoff rate of 10-inches per year (Reference VI-18), giving an average annual natural evapo-transpiration rate of 20-inches per year. For land areas corresponding to cooling pond sizes, the average evapo-transpiration rates in cfs are given as:

Land Area	Evapo-transpiration
1500 acres	3.5 cfs
1750 acres	4.0 cfs
2000 acres	4.6 cfs

TABLE VI-7

EVAPORATION RATES (cfs) - WET COOLING DEVICES

Case*	Mechanical Draft Tower		Natural Draft Tower		Cooling Pond (Flow-Through)		Spray Cooling Canal		Once-Through Cooling
	Design Condition	Average Annual	Design Condition	Average Annual	Design Condition	Average Annual	Design Condition	Average Annual	Average Annual
I	16.0	10.5	16.1	10.6	40.8	15.9	-	-	-
II	16.1	10.6	16.1	10.6	39.3	15.6	-	-	-
III	16.1	10.6	16.2	10.6	32.2	14.3	-	-	-
IV	16.1	10.6	16.2	10.6	39.3	15.6	-	-	-
V	16.1	10.6	16.2	10.6	35.7	15.0	-	-	-
VI	16.0	10.5	16.1	10.6	40.3	15.8	-	-	-
VII	16.1	10.6	16.1	10.6	32.5	14.4	-	-	-
Ave.	16.1	10.6	16.1	10.6	37.1	15.2	16.1[1]	10.6[1]	8.2[2]

*See Table III-1.

[1]Values approximated as equal to towers.

[2]Asbury (Reference VI-1), see following text.

These natural evapo-transpiration rates should be subtracted from the pond evaporation rates to give the net consumptive water loss due to the cooling ponds. When this is done, the consumptive water loss for the cooling ponds is less than one cfs greater than the evaporation losses from wet cooling towers.

Any discussion of the consumptive water loss due to wet cooling devices must also consider the increase in natural levels of evaporation caused by once-through cooling. For example, Asbury (Reference VI-1) estimates the increase of evaporation in Lake Michigan due to thermal discharges from power plants with once-through cooling to be 9 cfs for each 1000 MW_t (thermal) of waste heat discharged. A 1000 MWe fossil fueled plant wastes about 3800 Btu/KWH to the cooling water as compared to an electrical output of 3413 Btu/KWH. Thus, a 1000 MWe fossil plant with once-through cooling will increase natural lake evaporation by about (3800/3413)(9) = 10 cfs.

By using the plant capacity factor of 0.82 to adjust the 10 cfs figure, an average annual evaporation rate of 8.2 cfs is obtained for the once-through system. The relationship between this value and those given in Table VI-7 for the various cooling systems corresponds to the relationship proposed by Hauser and Oleson (Reference VI-15) and presented in Table VI-6. Therefore, when one compares the evaporation rates for wet towers and spray canals with the evaporation rate for once-through cooling, a difference of only (10.6 cfs minus 8.2 cfs =) 2.4 cfs exists. For cooling ponds, the difference is less than 3.4 cfs, when natural levels of evapo-transpiration are considered.

Drift

Drift is entrained water that is carried out of the top of a wet cooling tower or from a spray canal in liquid droplets rather than vapor. Drift can produce undesirable effects.

Waselkow (Reference VI-26) points out that "flash-over" of transmission lines was caused by excessive drift. This problem was solved by relocating the transmission lines. Waselkow recommends a 500-foot separation between cooling towers and transmission lines.

Recent surveys of existing power plant facilities (References VI-4, 6, 20, and 22) have uncovered only minor problems involving drift from freshwater towers. Drift is more likely to result from mechanical draft than from natural draft towers. However, in situations where drift has been noted, the area affected was limited to the immediate vicinity of the tower installation.

The typical drift guarantee of 0.2 percent of the circulating water flow is far in excess of current engineering capability and practicality for large towers. Drift can be almost completely eliminated by control of air velocity and design of drift eliminators. Mechanical draft towers can be purchased today with certification of drift elimination to the 0.02 percent level. Current developmental work by cooling tower manufacturers is expected to enable further reduction of drift.

Blowdown

As water is lost by evaporation from the cooling water supply of wet cooling devices, non-evaporating substances are concentrated in the remaining cooling water. There is a practical limit of concentration of the substances if scale corrosion and general deterioration of the cooling structures are to be prevented. To avoid such problems, a certain amount of the cooling water customarily is drained off the system for disposal. This water, termed blowdown, is replaced by fresh makeup water.

Blowdown, as it comes from the tower, contains concentrated solids and dissolved salts and minerals present in the original makeup water; it may contain special chemicals used to prevent scale and corrosion of condenser tubes and deterioration of wood structures; it may contain special algicides and fungicides; and, it is generally at a higher temperature than ambient lake or stream water. Hence, blowdown is an industrial waste in every sense of the word, subject to control under water quality standards.

The relationship between concentration of non-volatile, "conservative" constituents and design and operation of the cooling devices is:

$$C = \frac{E + D + B}{D + B}$$

where,

C = The multiple of concentrations of makeup water

E = Evaporative loss

D = Drift

B = Blowdown

Evaporation, drift, and blowdown are conventionally expressed as percent of circulating flow rate.

The volume of blowdown discharged to a receiving water is strongly influenced by the concentration multiple, but the temperature of the blowdown is independent of this factor. Therefore, the thermal pollution of Lake Michigan can be minimized practically to the point of extinction by increasing the concentration multiple.

The effect of concentration multiples on volume of blowdown from wet towers and spray canals for our typical 1000 MWe plant is demonstrated in Table VI-8. In these example computations evaporative losses are established from Table VI-7 and a figure of 0.05 percent is used for drift. With this figure for drift and assuming no leakage, the maximum concentration multiple that could be reached with no blowdown is 35:1. If drift is taken as 0.2 percent, the maximum concentration multiple is 9.5:1.

The concentration of dissolved solids in the Lake Michigan is very low. Hence, even with no blowdown the salt concentration of the circulating flow would not be at all unique to power plant operation in the United States.

TABLE VI-8

BLOWDOWN FROM WET TOWERS AND SPRAY CANALS

Concentration Multiple (C)	Evaporation Losses (E)	Blowdown (B)	
		%	cfs
1:1	1.7%	1.75	17
5:1	1.7%	0.38	4
10:1	1.7%	0.14	1
25:1	1.7%	0.02	0.2
35:1*	1.7%	0	0

*Maximum concentration multiple.

A 5:1 concentration multiple is frequently used as a generalization (Reference VI-13), but a survey of several power plants by FWQA reveals a very wide range in actual practice. DeFlon (Reference VI-12) and Southern Nuclear Engineering (Reference VI-22) cite concentrations of circulating flow in cooling towers up to 100,000 ppm total dissolved solids. The mechanical draft towers at the Mohave power plant in the arid southwest are designed for zero blowdown to receiving waters.

Table VI-9 shows average chemical concentrations found on two transects of Lake Michigan in 1962-63 (Reference VI-21). The southernmost transect (41°30'-41°45') is in the Chicago area and could be expected to have the most pollutants. The other transect (43°30'-43°45') runs from Pentwater, Michigan to Sheboygan, Wisconsin and was chosen because there are few streams or major waste inputs in the area. Included are potential concentrations in blowdown water, calculated at a ratio of 5:1. These concentrations compared to those permissible for public water supplies, do not appear to be high enough to cause concern. It also is obvious from Table VI-9 that treatment of blowdown to reduce hardness (Ca and Mg alkalinity) and heavy metal concentrations would allow much higher concentration multiples than 5:1.

TABLE VI-9

CHEMICAL CONSTITUENTS OF LAKE MICHIGAN WATER

	Lake Michigan Water Chemistry; Averages in 1962-63 and at Concentration of 5:1*				Permissible Surface Water Criteria For Public Water Supplies**
Latitude	41°30'-41°45'		43°30'-43°45'		
Parameter	Avg. mg/l	At Conc. of 5×	Avg. mg/l	At Conc. of 5×	mg/l
NH_3-N	0.16		0.07		
NO_3-N	0.12	0.60	0.19	0.95	10 (as N)
Total PO_4	0.06	0.30	0.02	0.10	
Alkalinity	105	525	110	550	400-500
Specific conductance as Micromhos/cm	280	1400	220	1100	
K	1.0	5.0	1.0	5.0	
Ca	34	170	33	165	
Mg	12	60	12	60	
SiO_2	1.7	8.5	2.9	14.5	
SO_4	22	110	21	105	250
ABS	0.04	0.20	0.05	0.25	
Cl^-	8.0	40.0	6.6	33.0	250
Phenols as µg/l	2.0		0.5		
Oil & Grease	7.5	37.5	-	-	Virtually absent

TABLE VI-9 (Cont.)

CHEMICAL CONSTITUENTS OF LAKE MICHIGAN WATER

	Lake Michigan Water Chemistry; Averages in 1962-63 and at Concentration of 5:1*				Permissible Surface Water Criteria For Public Water Supplies**
Latitude	41°30'-41°45'		43°30'-43°45'		
Parameter	Avg. mg/l	At Conc. of 5×	Avg. mg/l	At Conc. of 5×	mg/l
Turbidity in mg/SiO_2	2.7	13.5	0.9	4.5	
Cu	<0.005	<0.025	<0.005	<0.025	1.0
Cadmium	<0.005	<0.025	<0.005	<0.025	0.01
Chromium	<0.005	<0.025	<0.005	<0.025	0.05 (as Cr^6)
Pb	<0.005	<0.025	<0.005	<0.025	0.05
Ni	<0.005	<0.025	<0.005	<0.025	
Zn	<0.005	<0.025	<0.005	<0.025	5

*Risley and Fuller, 1965 (Reference VI-21)

**Interior, U. S. Department of, FWPCA, 1968, page 20 (Reference VI-16)

Table VI-10 shows the relationships of temperature of blowdown from wet cooling devices at design meteorological conditions and design summer lake temperature. Although these relationships would vary seasonally and with operating practices, the increase above ambient would be appreciable in all cases. However, the effects of blowdown temperatures on Lake Michigan cannot be projected out of context from the volumes of blowdown discharged. See Table VI-8.

If makeup water is taken from Lake Michigan (or similarly dilute sources) blowdown can be reduced to almost any level without hazard from salt discharged to the atmosphere by drift. As shown in Table VI-9 Lake Michigan water is non-corrosive and the chloride concentration is very low.

Blowdown may also contain chemicals which are added to the cooling water for special control purposes (See Table VI-11). Many of these are toxic and may have to be treated to comply with water quality standards, a task which Donahue (Reference VI-13) claims can be accomplished economically.

Toxicants in blowdown can be controlled by careful choice of treatment chemicals to ensure use of those which will do the job with the least effect on the environment. For example, chlorine used for prevention of fouling is lost in the tower through evaporation and residual chlorine in blowdown can be very low. But, other anti-fouling agents, such as mercuric compounds,are very toxic and should be avoided.

TABLE VI-10

TEMPERATURE OF BLOWDOWN AT DESIGN CONDITIONS

Wet Cooling Device	Blowdown Temperature (°F)	Lake Temperature (°F)	Temperature Difference (°F)
Mechanical Draft Tower	88	68	20
Natural Draft Tower	84	68	16
Spray Canal	90	68	22

TABLE VI-11

SUMMARY OF CHEMICAL TREATMENTS*

Potential Problem	Factors	Causative Agents	Corrective Treatments
Wood Deterioration	Microbiological Chemical	Cellulolytic fungi Chlorine Sodium Carbonate	Fungicides Acid
Biological Growths	Temperature Nutrients pH Innoculants Deposits	Bacteria Fungi Algae	Chlorine Chlorine Donors Organic Sulfurs Quatenary ammonia
General Fouling	Suspended Solids Water Velocity Temperature Contaminants Metal Oxides	Silt Oil	Polyelectrolytes Polyacrylates Lignosulfonates Polyphosphates
Corrosion	Aeration pH Temperature Dissolved Solids Galvanic Couples	Oxygen Carbon dioxide Chloride	Chromate Zinc Polyphosphate Tannins Lignins Synthetic Organics

TABLE VI-11 (Cont.)

SUMMARY OF CHEMICAL TREATMENTS*

Potential Problem	Factors	Causative Agents	Corrective Treatments
Scaling	Calcium	Calcium Carbonate	Phosphonates
	Alkalinity	Calcium Sulfate	Polyphosphates
	Temperature	Magnesium Silicate	Acid
	pH	Ferric Hydroxide	Polyelectrolytes

*From: Donahue, page 37 (Reference VI-13)

If high concentrations of toxicants are necessary in the cooling system, they require treatment before release. For example, toxicant hexavalent chromates can be reduced by reaction with sulfides and the excess sulfides removed by aeration; chromium and copper salts may be reduced by contact with lime and copper ash (Reference VI-19).

In summary, blowdown composition will vary with plant design and operation and with intake water quality. Adverse effects can be minimized by trade-offs in plant and tower design or by chemical treatment of outlet water.

Summary

While cooling devices do have the potential for producing undesirable environmental effects, such effects do not seem to be a problem for the Lake Michigan area. Careful pre-site selection surveys should eliminate sites which have a high potential for fog or drift problems, and blowdown treatment can be provided, if necessary. Site by site evaluation of the potential for consumptive water loss by evaporation may be necessary.

Lake Michigan temperature standards can be met by (1) design and operation of wet cooling systems with no, or essentially no, blowdown, (2) dilution of any residual blowdown with Lake Michigan water, (3) dry cooling towers, or (4) construction of closed cycle systems at sites independent of Lake Michigan as source of water supply or sump for blowdown.

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VII. CONCLUSIONS

Based on the results presented in this report, it is concluded that any of the six cooling systems evaluated are feasible alternatives to once-through cooling for thermal power plants around Lake Michigan. The absolute magnitude of the numbers derived in the analysis cannot be applied to specific plants because of unique site differences, but the numbers do indicate feasibility.

Meteorologic conditions throughout the study area do not impose restraints that are beyond present-day capabilities in terms of engineering design and continuous operation of the alternative cooling systems.

The impact of alternative cooling systems on the environment appears to be minor. Potential problems can be avoided or alleviated through proper site selection and engineering design.

The maximum economic penalty for each type of cooling system in terms of the approximate percent increase in power generation (busbar) cost above that involving a once-through system is:

Wet mechanical draft tower..............1½%
Wet natural draft tower.................3%
Cooling pond..........................<1%
Spray canals............................1%
Dry mechanical draft tower.............10%
Dry natural draft tower.................9%

As indicated, the maximum economic penalty among all wet cooling systems is about 3 percent. The magnitude of this penalty (about 0.2 Mills/KWH) is roughly equivalent to any one of the following:

a) A $10/KW difference in plant capital cost,

b) A 1 percent difference in fixed charge rate,

c) A 2¢/10^6 Btu difference in fuel cost, or

d) An 80-mile difference in power transmission distance.

When a closed-cycle cooling system is chosen for a new plant, more latitude in plant siting is gained because large volumes of cooling water are no longer a site prerequisite. According to the Geological Survey Water-Supply Paper 1800, the area around Lake Michigan is generally one of moderate to high surface water runoff and groundwater availability. Therefore, make-up water acquisition should not pose problems at selected inland plant sites.

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